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REPORT 88-E

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ERCB

Alberta Oil Supply
1988 - 2003

December 1988

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ALBERTA OIL SUPPLY, 1988 - 2003

Report 88-E published December 1988

Published by:

Energy Resources Conservation Board
640 Fifth Avenue S.W.
Calgary, Alberta
T2P 3G4

Telephone (403) 297-8311

Telex 03-821717

Price: $25.00

BOARD OVERVIEW

The current update of Alberta's crude oil supply has been prepared in a period of continuing uncertainty respecting the longer term direction of oil prices and the resulting economic fortunes of the industry. For this reason, rather than use a single oil price forecast, the Board used a band of possible future prices as a basis for projecting future supplies. The upper limit of the band has been designated as Base Case 1, the lower limit as Base Case 2. The Board made an additional projection, for sensitivity purposes, corresponding to a much lower oil price forecast. This low price case is largely an illustration of what could result if low prices were to prevail in the long run and there were no adjustments to domestic fiscal regimes.

Notwithstanding the many uncertainties, the Board believes that the cases discussed in the report generally reflect the broad range of outcomes that are most likely to evolve.

In the short run, the Board accepts that global excess supply may result in lower prices than shown in the base cases, and some downward adjustment in the available supply. In the longer term, however, the Board expects the supply and demand to come more into balance. This should stabilize and strengthen the international market and generate prices close to the base cases.

Continuing weak and volatile crude oil prices are likely to have the greatest impact on the bitumen and heavy oil segment of the industry. Higher operating costs, market uncertainty, and lower profit margins will result in a cautious approach to development. Timing of new large-scale synthetic crude oil plants would also be affected if the recent low price levels continue. Given the enormous resource base, however, the Board is convinced that technological improvements and the public need for development will inevitably lead to further commercial development of the oil sands.

The above views respecting the likely pricing regime lead the Board to conclude that crude oil production will be at the Base Case 2 level or perhaps slightly lower for at least the next year. Generally, however, during the early 1990s the Board expects a transition towards Base Case 1. The latter represents the Board's best judgement, at this time, as to what the outlook for available crude oil supply might be from 1995 onward.

G J DeSorcy

G. J. DeSorcy
Chairman

EXECUTIVE SUMMARY

The Board's current assessment of Alberta's crude oil and equivalent supply provides an update to the forecasts presented in ERCB Report 85-A.

Updated estimates of the ultimate potential for light and heavy crude oil, pentanes plus, and bitumen (mining and in situ) are summarized in Table 1. Reserves have been significantly increased relative to those reported in ERCB Report 85-A, except for the in situ portion of bitumen which remains unchanged.

The Board's detailed geological reassessment of conventional in-place reserves shows:

- The ultimate potential for light and heavy crude oil and pentanes plus has been increased to a combined total of 3335 x 10^6 m^3, which is 7 per cent higher than the 1985 estimate.
- The established reserves of pentanes plus have increased by 14 per cent, largely because of the discovery of the Caroline Pool.

The total ultimate potential for bitumen that would be extracted by mining operations has been increased to 10 000 x 10^6 m^3, which is 43 per cent higher than was recognized in ERCB Report 85-A. The higher estimate of ultimate potential is the same as contained in the Board's 1985 reserves report, ERCB ST 86-18.

The total ultimate potential for bitumen reserves amenable to in situ recovery has remained unchanged at 39 000 x 10^6 m^3.

Based on the revised reserves estimates, the Board forecast future annual supply of crude oil and equivalent by considering three different price scenarios. The most optimistic of the price forecasts (referred to as Base Case 1) starts with an oil price of about \$23 US/bbl (or \$19 US/bbl in constant \$1987) in 1990, which increases to nearly \$50 US/bbl (\$28 US/bbl in constant \$1987) by the year 2000. A slightly less optimistic scenario (referred to as Base Case 2) begins with an oil price of about \$19 US/bbl (or \$17 US/bbl in constant \$1987) in 1990, increasing to about \$39 US/bbl (or \$22 US/bbl in constant \$1987) by the year 2000. The third scenario (referred to as the Low Price Case) reflects recent pessimism regarding energy prices, and starts with an oil price of about \$15 US/bbl (or \$13 US/bbl in constant \$1987) in 1990, gradually increasing to only about \$27 US/bbl (or \$15 US/bbl in constant \$1987) by the year 2000.

The forecasts of total oil supply from Alberta over the interval 1988 to 2003, based on the three price scenarios, are illustrated on Figure 1. A narrow range of expected supply is bounded by Base Cases 1 and 2. Specifically, the forecasts predict that:

- In all instances, the conventional crude oil supply is expected to decline moderately by the mid-1990s. The rate of decline is influenced significantly by industry activity.

- Pentanes plus supply is identical in all three cases, since production is more directly related to gas markets than it is a function of oil prices.

- Total supply in Base Cases 1 and 2 is expected to be maintained at 220 x 10^3 m^3/d or higher over the forecast interval. Forecast declines in conventional crude oil production are largely offset by increases in bitumen and synthetic crude oil (SCO) production.

- Total supply in the Low Price Case is expected to peak at 234×10^3 m^3/d in 1989 and decline to 153×10^3 m^3/d by the year 2003. This decline in total supply, compared to the other cases, results from a slowdown in activity in the bitumen sector and a significant and sustained reduction in drilling activity in the conventional industry.

- If the upper geological potential materializes, the conventional supply would be about 20 per cent higher in 2003 than projected for the base cases.

TABLE 1 SUMMARY OF THE ULTIMATE POTENTIAL OF CRUDE OIL AND EQUIVALENT - ALL SOURCES
(millions of cubic metres)

	1 Light	2 Heavy	3 Pentanes Plus	4 Bitumen[b] Mining	5 In Situ
Initial Established[a]	2 050	145	294	5 300	84
Cumulative Production[a]	1 487	95	165	133	22
Remaining Established[a]	563	50	129	5 167	62
Discoveries /Additions	350[c]	115[c]	136	-	-
Tertiary	195	50	-	-	-
Future Potential	-	-	-	4 700	38 916
Ultimate Potential	2 595	310	430	10 000	39 000
Total Remaining Potential	1 108	215	265	9 867	38 978

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a Effective 31 December 1987.

b Columns show raw bitumen, not SCO.

c Assumes development of reserves with medium geological potential (see Section 3.1).

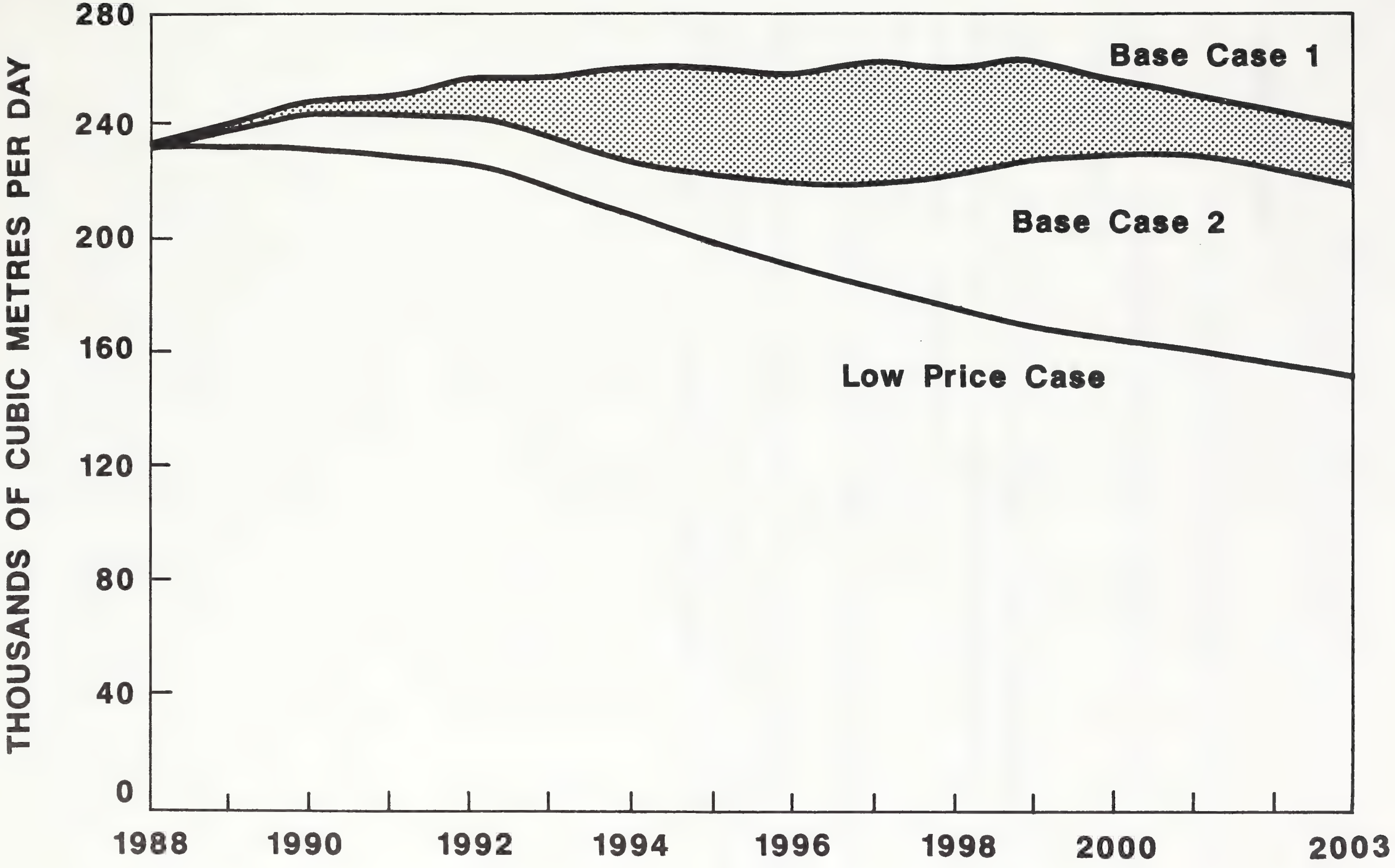

FIGURE 1 TOTAL SUPPLY OF ALBERTA'S CRUDE OIL AND EQUIVALENT

ACKNOWLEDGEMENTS

This report was prepared under the direction of F. J. Mink, with key contributions by:

Terry Hurst, Barry Christensen, LeMoine Philp - Conventional Crude Oil
Terry Abel, Paul Kahler - Bitumen and Synthetic Crude Oil
Harvey Halladay - Pentanes Plus
Kevin Johnston - Economic Considerations
Milan Vrskovy, Ed Niewinski, Ali Beken - Geological Evaluations

The Board extends its appreciation to the Canadian Petroleum Association and the Independent Petroleum Association of Canada for their comments at various stages in the preparation of this report.

TERMINOLOGY

RESERVES TERMINOLOGY

Established Reserves	Those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing, or production, plus a reasonable estimate of contiguous recoverable reserves that are interpreted to exist, from geological, geophysical, or similar information.
Initial Reserves	Reserves prior to the deduction of any production.
In-place Reserves	The gross volume of crude oil, bitumen, or pentanes plus calculated or interpreted to exist in a reservoir before any volume has been produced.
Remaining Reserves	Initial reserves less cumulative production.
Ultimate Potential	An estimate of the initial established reserves which will have been developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions.

Ultimate potential includes cumulative production, remaining established reserves, and future additions through extensions and revisions to existing pools and the discovery of new pools. Ultimate potential can be expressed by the following single formula:

Ultimate potential = Initial established reserves + additions to existing pools + future discoveries.

The above reserves terminology and definitions, which were recommended by the Inter-Provincial Advisory Committee on Energy (IPACE), have been adopted by the Board.

DEFINITIONS OF OTHER TERMS

Crude Bitumen	A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds and that, in its naturally occurring viscous state, will not flow to a well.
Crude Oil (Conventional)	A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that is recovered or is recoverable at a well from an underground reservoir, and that is liquid at the conditions under which its volume is measured or estimated, and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas or condensate.

Crude Oil (Heavy)	Crude oil will be deemed to be heavy crude oil if it has a density of 900 kg/m^3 or more, but the Board, in a particular case, may classify crude oil otherwise than in accordance with this criterion, having regard to its market utilization and purchasers' classification.
Crude Oil (Light)	For the purposes of this report the term light crude oil is intended to include all light-medium crude oils of density less than 900 kg/m^3. In a particular case, the Board may classify crude oil otherwise than in accordance with this criterion, having regard to its market utilization and purchasers' classification.
Crude Oil (Synthetic)	A mixture of pentanes and heavier hydrocarbons, that may contain sulphur compounds, that is derived from crude bitumen, and that is liquid at the conditions under which its volume is measured or estimated, and includes all other hydrocarbon mixtures so derived.
Discoveries/Additions	As well as new discoveries, the term used in this report includes extensions or additions to existing pools and the application of conventional enhanced recovery by waterflood to those resources.
Experimental	A pilot test to evaluate techniques for recovery of crude bitumen, crude oil, condensate, or gas using methods that are considered untried and unproven in the particular situation.

Gas	Raw gas or marketable gas or any constituent of raw gas, condensate, crude bitumen, or crude oil that is recovered in processing and that is gaseous at the conditions under which its volume is measured or estimated.
Infill Drilling	The drilling of wells within a pool in addition to those completed in the drilling spacing units under which the pool was developed.
Oil	Condensate or crude oil, or a constituent of raw gas, condensate, or crude oil that is recovered in processing, that is liquid at the conditions under which its volume is measured or estimated.
Oil Sands	(i) sands and other rock materials containing crude bitumen, (ii) the crude bitumen contained in those sands and other rock materials, and (iii) any other mineral substances, other than natural gas, in association with that crude bitumen or those sands and other rock materials referred to in subclauses (i) and (ii).
Pentanes Plus	A mixture mainly of pentanes and heavier hydrocarbons which ordinarily may contain some butanes and which is obtained from the processing of raw gas, condensate, or crude oil.

Pool	A natural underground reservoir containing or appearing to contain an accumulation of oil or gas or both, separated or appearing to be separated from any other such accumulation.
Tertiary	Recovery of crude oil from a reservoir by an unconventional enhanced recovery method. (Excluded from this definition are the conventional, widely applied enhanced recovery methods of waterflood and immiscible gas injection.) Some tertiary recovery methods or processes are: (a) miscible floods using solvent (hydrocarbon) or carbon dioxide, (b) thermal floods using in situ combustion or steam injection.

SI UNITS

This report has been prepared in the International System of Units (SI). Conversion factors that may be used in calculating the imperial equivalent of the SI Units used in the report are listed below:

1 cubic metre of gas (101.325 kilopascals and 15° Celsius)	= 35.493 73 cubic feet of gas (14.65 psia and 60° Fahrenheit)
1 cubic metre of oil or pentanes plus (equilibrium pressure and 15° Celsius)	= 6.292 9 Canadian barrels of oil or pentanes plus (equilibrium pressure and 60° Fahrenheit)

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1 INTRODUCTION

The Energy Resources Conservation Board (the Board) periodically reviews and updates Alberta's long-term supply of crude oil. In ERCB Report 81-B, which was issued in January 1981, the Board evaluated the potential crude oil supply of Alberta by soliciting industry submissions and reviewing the presentations at a formal Board hearing. Subsequent ERCB Reports 83-E and 85-A, updates of the earlier forecasts, were issued in December 1983 and March 1985, respectively, and were prepared entirely in-house by Board staff.

In early 1988 the Board undertook to review and update its long-term crude oil supply outlook in order to assist government and industry in evaluating the long-term needs for transportation capacity. The evaluations were carried out largely by ERCB staff through its own analysis and some consultation with representatives of the industry.

The Board released a short-term forecast of conventional crude oil (1988-1992) on 5 August 1988. The companion document on the methodology used to generate this short-term forecast is attached as Appendix A. It should be noted that the forecasts contained in Appendix A have been modified slightly as a result of the Board's findings on the long-term assessment of available supply.

The Board has adopted the long-term forecasting methodology used in previous studies, but based its current projections on a more detailed evaluation of reserves and productivity. There are two major differences between this report and past studies:

- A comprehensive geological assessment of ultimate potential for conventional crude oil has been completed and included in Section 3 of this report.

- The impact on oil supply of three price forecasts have been evaluated in this report. In previous reports one set of economic conditions was assumed to prevail over the forecast period. In this instance, an expected narrow range of supply is bounded by an upper Base Case 1 and a lower Base Case 2. In view of the recent volatility in world oil prices and speculation that a much lower oil price may persist for some time, the Board has also included a Low Price Case. Details on the economics of the three price cases are provided in Section 2 of this report.

2 ECONOMIC CONSIDERATIONS

The Board postulated three different price forecasts to capture the broad range of influences that different prices would have on each sector of the industry. The Base Case 1 forecast is the most optimistic. It assumes that nominal prices of benchmark light oil would average nearly $21 US/bbl in 1989, climbing to $33/bbl and almost $50/bbl in 1995 and 2000, respectively. This would reflect an average real price increase of about 4 per cent per year. The circumstances that would be necessary for such an optimistic forecast to be realized would likely have to include:

- A high degree of discipline among OPEC members with a commitment to curtail production as necessary to bolster prices.
- Continued increases in U.S. demand relative to U.S. supply with corresponding growth in U.S. net imports of crude oil and products.
- A willingness and ability to finance imports of crude oil and products in developing countries lacking in domestic petroleum resources.
- No significant impact by alternative energy sources, such as nuclear, hydroelectric, and the so-called "soft" energy sources, on oil's share of energy supply.

Somewhat less optimistic, but still reflecting a good deal of co-operation among OPEC members, the Base Case 2 forecast assumes that light crude oil prices at Chicago would average about $18.50 US/bbl in 1989, gradually climbing to $28.50/bbl in 1995, and reaching $39/bbl by 2000. This would reflect an average real price increase of about 3 per cent per year. This forecast may also appear optimistic in light of events over the last few months. Keeping in mind, however, that the price drop that has occurred of late is likely a result of the cessation of hostilities between Iran and Iraq, the decline may well be surmountable through OPEC co-operation. Thus, if OPEC can maintain control of production sharing, the Base Case 2 forecast is plausible.

A third scenario, the Low Price Case, has been postulated out of recognition of the recent weakness in oil prices. This pessimistic outlook has current prices at Chicago averaging nearly $15 US/bbl in 1989, about $18/bbl in 1995, and $27/bbl in 2000. This would reflect a loss in the real value of oil by about 1 per cent per year until 1995 and then an average real price increase of about 4 per cent per year to the year 2003. Of the growth in prices assumed between 1989 and 2000, approximately $10/bbl results from an underlying rate of inflation of 4 per cent per year, while the remaining $2/bbl growth represents an increase in the real value of the resource.

The Low Price Case would reflect circumstances where:

- OPEC would no longer be able to restrain production among member countries.

- Oil supply elasticity would be such that significant additional production would be forthcoming at prices in the range of $17-$20 US/bbl. Thus, if prices were to approach these levels through to the mid-1990s, sufficient additional supply would be forthcoming to dampen any further upward pressure.

- Only in the latter part of the 1990s does international supply become scarce relative to demand and thus justify price increases.

The three price forecasts are shown in Figure 2-1.

The Board did not consider the possible effects of different tax and royalty regimes in this report. Rather, it was assumed that current tax and royalty regimes would continue regardless of the price.

With the Base Case 1 and 2 price forecasts, provincial royalty holiday programs were assumed to be discontinued upon their expiry dates. As well, the federal and provincial income tax programs were assumed to remain largely as they appear now under the premise that, while prices are adequate to ensure a healthy industry, there would not be a perception that a further redistribution of income would be necessary if, for example, prices were to reach $40 US/bbl as indicated by the Base Case 1 forecast.

In the Low Price Case, production from all sources was estimated assuming no major changes to current policies, including the discontinuation of provincial royalty holidays. The intent of the Low Price Case was to forecast a plausible production profile without any special fiscal efforts being made to offset relatively low prices.

There are different degrees of responsiveness from each sector when prices drop from their Base Case 1 and 2 levels to the Low Price Case. The strongest reaction would occur in the bitumen and synthetic crude oil (SCO) sectors, as might be expected considering the large capital outlays that are required and the relatively long payback period.

The next strongest response to such a price decline would occur in the discoveries/additions components of light and heavy crude oil. As well, stripper wells could be affected, although not by enough to impact total production significantly. Tertiary production could be reduced under the lower price forecast; however, provisions within the provincial royalty system would probably offset lower prices to some extent.

Pentanes plus production, as a component of natural gas, is more a function of the state of North American gas markets than it is a function of oil prices. Therefore, pentanes plus production is expected to be largely insensitive to oil price fluctuations within the range projected in this report.

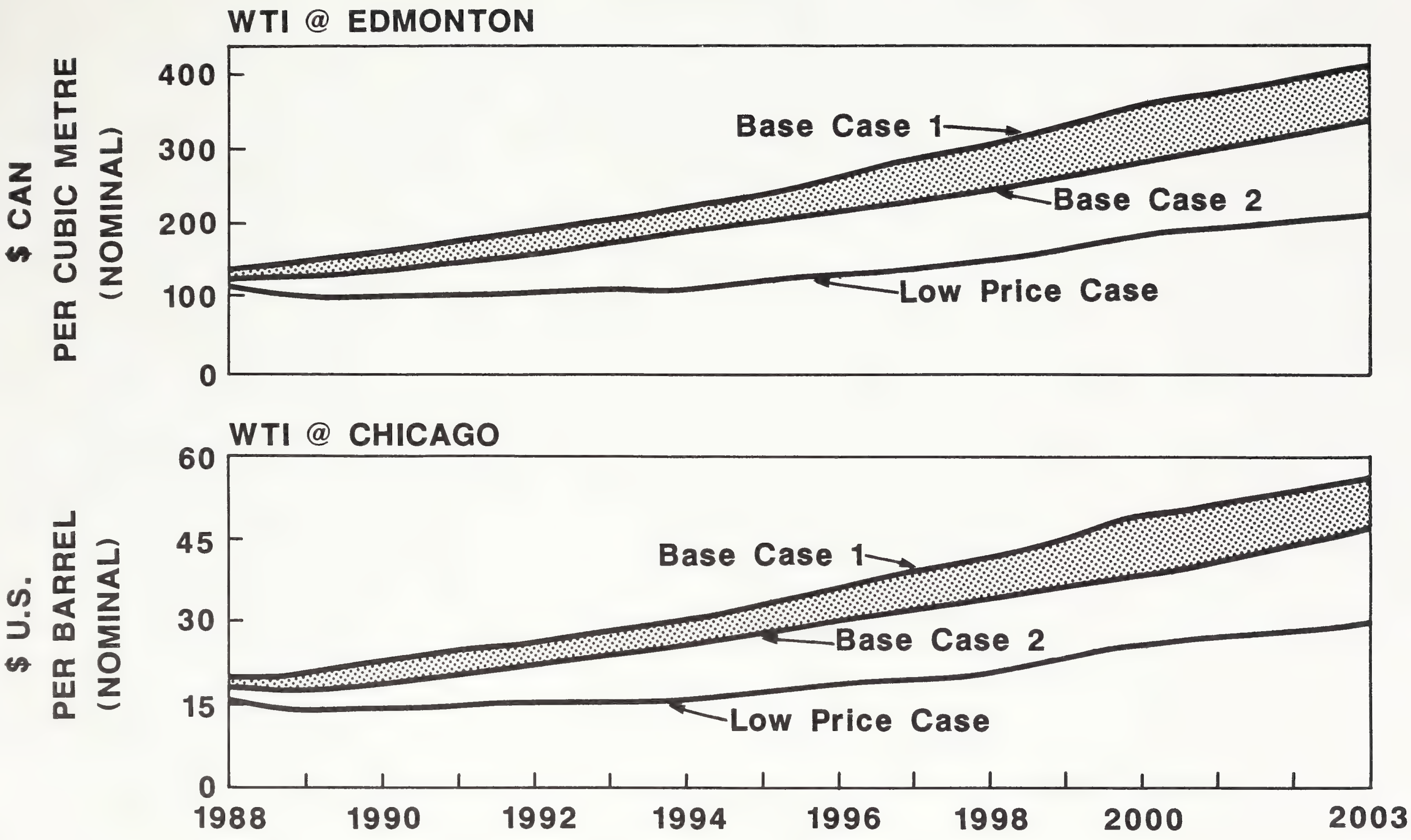

FIGURE 2-1 PRICE FORECASTS

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3 CONVENTIONAL CRUDE OIL SUPPLY

The Board based its long-term forecast of conventional crude oil supply on the economic conditions described in Section 2. This section addresses Base Cases 1 and 2, while a sensitivity case evaluating the supply based on a pessimistic price forecast and an upper geological potential case are included in Section 7.

The forecast of supply from remaining established reserves used the most current reserves and production data available, and cumulative production statistics to year-end 1987.

A detailed geological review of all oil-bearing formations in Alberta was conducted to estimate undiscovered ultimate potential from future discoveries/additions. The results of this evaluation for both light and heavy crude oil are presented in Section 3.1.

Normalized productivity profiles for light and heavy discoveries /additions have been adjusted to reflect recent evidence in the field, including acceleration effects due to infill drilling. The Board also reviewed approved schemes and projected future reserves additions to determine the supply from new tertiary operations.

The detailed results of the forecasts for light and heavy crude oil are presented in Sections 3.2 and 3.3, respectively.

3.1 ULTIMATE POTENTIAL - UNDISCOVERED RESERVES

3.1.1 Light Crude Oil

To evaluate the long-term supply prospects in Alberta, it is critical to identify the undiscovered reserves potential. To do so, a detailed geological review of the resource potential in the sedimentary basin was carried out.

The results of the Board's geological study of the ultimate potential of light crude oil in Alberta are summarized in Table 3-1. The remaining in-place reserves yet to be discovered are estimated to be 1.20×10^9 m^3, 1.40×10^9 m^3, and 1.82×10^9 m^3. These figures represent the range of reserves corresponding to the lower, medium, and upper geological potential cases, respectively. They also reflect the respective upper, medium, and lower degrees of confidence in the geological assessments.

The Board's study employed a geological-statistical methodology to predict the ultimate potential of crude oil reserves present within all oil-bearing units located in the stratigraphic column of Alberta. The stratigraphic column was divided into fifteen major units which were further subdivided and analysed as exploration plays of either a formation or a group of formations within a stratigraphic unit. The subdivision allowed the entire province to be separated into geologic regions within specific geographic areas and also provided the basis for comparisons to ultimate potential figures derived for similar units, described in the Geological Survey of Canada Paper 87-26. The entire sedimentary basin within the province was reviewed for its ultimate potential, excluding the disturbed belt, which is considered primarily gas prone.

The geological assessment was based on the assumption that historical discoveries of pools made in the course of developing a sedimentary basin represent a typical sample of basin play development. The addition of the undiscovered plays represents the total resources for the basin. In this study, individual formations or groups of formations were separated into a number of geologic regions distinguished by unique geologic features such as structural boundaries or depositional trends. Subsurface maps were generated to relate sedimentologic and structural models to explored areas and areas of sparse development. For example, the locations of the Leduc carbonate reefs provided the basis for the creation of geologic regions. The structural or stratigraphic controls necessary to explain carbonate deposition or pool developments were noted. Also, the drilling density to the Leduc or equivalent geologic time formations, in conjunction with discovered pools, was reviewed in each region.

In explored areas, the size range and number of pools already discovered provided the base for the estimates of new discovery pool profiles. The historical rate of expansion in the development of older existing pools assisted in the prediction of the potential growth of small and single-well pools. In studying the potential development of the pools, the analysis focused on the relevance of existing models in making assessments of the size distribution, pool numbers, and quality of reservoirs. For example, the sizes and numbers of discovered Leduc pools, their positions relative to carbonate trends, and the anticipated type of new pools were projected into areas of undrilled acreage to predict the size and numbers of new pools.

In relatively unexplored areas, the analysis considered pools from established plays in other regions with similar lithology, sedimentology, and trapping mechanisms. As in the explored areas, trends from discovered pools were used to predict the quality and quantity of undiscovered pools.

The review of historical data from 1983 to 1987 provided the foundation for the division of ultimate potential into three ranges: lower, medium, and upper. The lower geological potential category can be explained as volume growth resulting from expansion of established pools and continued development drilling of known reserves, as well as reserves additions of undiscovered pools on trend with known reserves. The medium category of reserves includes the above plus the development of undiscovered pools within the bounds of defined play areas. The upper geological potential category includes new discoveries in some of the sparsely drilled areas or conceptual plays in the province, plus the effect of new exploration and production technology. Given the historic pattern of resource development and the judgements applied, there appears to be more than a 50 per cent probability that all the resources would be discovered under the three cases.

The major conclusions of the geological study are:

- Future crude oil reserves will be found in pools of small areal extent and volume, and in the expansion of discovered pools.
- Major large pools are unlikely to be discovered in the future.
- Geologic models for each formation or stratigraphic unit appear to be a valid and effective tool for basin analysis.
- The established reserves in several formations, based on 1987 reserves figures, already exceed the ultimate potential that was determined in the G.S.C. Paper 87-26, based on 1983 and 1985 reserves data. In some other formations the discoveries /additions since 1985 are greater than 50 per cent of the G.S.C.'s estimate of undiscovered reserves.

The average recovery factor for light crude oil pools at year-end 1987 (excluding tertiary reserves but including waterflood) was found to be about 29 per cent. The Board's analysis showed that in applying the current average recovery factors for individual formations to the expected distribution of reserves to be discovered, the recovery factor for future discoveries/additions was, coincidentally, calculated to be 29 per cent. However, considering that pools discovered in the future are expected to be of smaller size and lower quality, the Board believes it is more likely that the average recovery factor for future discoveries/additions would be closer to 25 per cent.

With a recovery factor of 25 per cent, the resulting reserves additions for future discoveries/additions are 350 x 10^6 m^3 and 450 x 10^6 m^3 for the medium and upper geological potential cases, respectively. The medium geological potential case was used in the Base Cases 1 and 2 and low price analyses. The upper geological potential case was used in the sensitivity analysis presented in Section 7. Given recent reserves acquisition trends, the lower geological potential reserves were considered to be overly pessimistic and were not considered in this report.

3.1.2 Heavy Crude Oil

A detailed geological study, similar to the review for light crude oil discussed in Section 3.1.1, was conducted to determine the ultimate potential of heavy crude oil in Alberta. The results are summarized in Table 3-2. The remaining in-place reserves yet to be discovered are estimated to be 820 x 10^6 m^3, 975 x 10^6 m^3, and 1300 x 10^6 m^3 for the lower, medium, and upper geological potential cases, respectively. As indicated in the discussion for light crude oil, this would represent an upper, medium, and lower degree of confidence in the geological assessment. In the evaluation of Alberta's heavy crude oil potential, the geological analysis focused on two main areas.

Lloydminster Area

The Lloydminster area is bounded by Townships 34 to 52 and Ranges 1 to 7 W4M, and contains approximately 4800 sections of land. Most of the heavy oil reserves in the Lloydminster area are contained within the Mannville Group of Lower Cretaceous age. The total thickness of the Mannville Group varies greatly, from 80 to 250 metres, and is comprised of interbedded sandstones and shales. The structural framework for the Mannville sands is influenced by the underlying Paleozoic unconformity, resulting in a northwesterly strike and southwesterly dip for the Mannville Group. Most of the nine recognized heavy oil-bearing zones consist of sandstones that are poorly consolidated, and contain fine-grained quartz sometimes grading into silt.

The Mannville sands are deposited as either blanket- or channel-type deposits. The channel-type sands are areally very limited but form thick prolific reservoirs. The blanket-type sand accumulations are of limited thickness but are much more widespread areally and they contain most of the reserves in the Lloydminster area. The Sparky Member is the most prolific producer, containing almost half the reserves in the Lloydminster area. The Dina sand is the main zone of production in the numerous, recently discovered, heavy oil pools in the Provost Field, within the southern portion of the Lloydminster area.

The methodology for calculating the ultimate resource potential considered the areal distribution of the total discovered reserves in comparison to the total available area, rather than average well discovery rates. Of the 2050 drilled sections, 860 contain at least one successful oil well, yielding a success ratio of approximately 40 per cent. The total discovered reserves of 634 x 10^6 m^3 implies reserves of 0.74 x 10^6 m^3 per successful section. Having regard for the widespread nature of the Mannville sands, the Board believes the demonstrated success rate and average reserves per successful section could reasonably be generalized across the area. This assumption is supported by the fact that the Lloydminster area contains several Mannville sand units, one or more of which exhibit varying degrees of heavy crude oil saturation throughout the area.

Recognizing, however, that the larger and better quality pools have likely already been discovered and that future discoveries may not be as prolific as in the past, a range of success rates was assumed for the 2750 sections of undrilled, undeveloped land in the Lloydminster area. Thus, the Board has a high degree of confidence with a success rate of 25 per cent, is reasonably confident with 30 per cent, and considers a 40 per cent success rate to be optimistic. The ultimate potential with a 25 per cent success rate is 500 x 10^6 m^3; with a 30 and 40 per cent success rate, it is 600 x 10^6 m^3 and 800 x 10^6 m^3, respectively.

In the Lloydminster area over the last 8-year period, set in-place reserves increased by 70 per cent, from 371 x 10^6 m^3 to 634 x 10^6 m^3.

During the same period the number of wells drilled increased by 60 per cent, from 5159 to 8284. It is expected that this trend will continue; that is, over the forecast period discoveries will be directly related to the drilling activity in the area.

Other Areas

More than 50 per cent, some 675 x 10^6 m^3, of Alberta's conventional heavy oil reserves are found outside the Lloydminster area. These reserves are located in over 1700 pools in 88 fields situated in southern and central Alberta, and are generally associated with the Bow River System.

The methodology for estimating the heavy oil ultimate potential in these areas was based on two assumptions:

- Future heavy oil discoveries will be limited to those geological formations which are already known to contain the existing heavy crude oil reserves. These formations are limited to the Lower Cretaceous, Jurassic, Mississippian, and Upper Devonian periods, with the Cretaceous containing approximately 90 per cent of the total reserves.

- The existing ratio of heavy crude oil to light crude oil will continue for future reserves in each geological formation.

Upon completing its comprehensive study of the geologic potential for light crude oil in the province, the Board reviewed the historical ratios of heavy to light crude oil in certain geological formations. These heavy/light ratios were determined to be 60 per cent for the Lower Cretaceous, 25 per cent for the Jurassic, 8 per cent for the Mississippian, and less than 0.5 per cent for the Upper Devonian. Applying the same percentages to the future discovery estimates of light crude oil reserves, future discovery estimates of in-place reserves were obtained for heavy crude oil in other areas.

In the areas outside Lloydminster, in-place heavy crude oil reserves over the last 8-year period have increased by 189 x 10^6 m^3, from 486 x 10^6 m^3 to 675 x 10^6 m^3 (an increase of approximately 40 per cent). This dramatic increase in reserves is due to inadvertent discoveries of heavy while searching for light, and to intentional exploration for heavy (eg, Grand Forks, Taber, Hays, etc). The Board believes that if a concerted effort were made toward exclusive development of heavy crude oil reserves, discoveries would increase substantially.

As discussed in Section 3.3.1, a review of established pools suggests that the average recovery factor for heavy crude oil is higher than previously projected. The updated reserves for established pools reflect a recovery factor of 8 per cent for the Lloydminster area and approximately 18 per cent for other areas.

With the above recovery factors and with the results from the geological assessment, the recoverable reserves values for future discoveries /additions are 115 x 10^6 m^3 and 155 x 10^6 m^3 for the medium and upper geological potential cases, respectively.

3.2 LIGHT CRUDE OIL SUPPLY

3.2.1 Supply from Established Pools

Actual 1987 production of light crude oil averaged approximately 129 x 10^3 m^3/d, although production was restricted in the first half of the year because of limited pipeline capacity. Production rates increased in the second half of the year, as a result of an expansion to Interprovincial Pipeline in mid-1987. Consequently, as illustrated in Figure 1 of Appendix A, the production rate generally increased throughout the second half of 1987 and reached 138 x 10^3 m^3/d by December 1987. The introduction of the Modified Proration Plan on

1 June 1987 also encouraged unrestricted production levels from virtually all pools for the last half of 1987. Accordingly, the Board believes the actual pool performance during this unrestricted period provides the best base to determine the available supply from established pools.

The current forecast is based on the performance of all producing pools as of year-end 1987. The Board reviewed the unrestricted production of the largest 190 pools, representing approximately 80 per cent of the total provincial productivity, and forecast their expected future productivity individually. Extrapolation of historical decline trends necessitated minor reserves changes in only a few pools. Significant productivity declines in four major D-2 and D-3 pools (Bonnie Glen, Fenn-Big Valley, Westerose, and Wizard Lake) over the past 5 years have largely removed the uncertainty associated with these pools in the past.

The current forecast predicts an average annual productivity decline from existing pools of about 10 per cent over the next 10-year period, which is consistent with recent historical decline trends. (See Appendix A for further details.) The average annual decline rate is expected to be more moderate for the duration of the forecast, reflecting the higher contribution from lower productivity pools (eg, Pembina Cardium).

As indicated, the production rate of 138 x 10^3 m^3/d from December 1987 was used as a base for predicting supply from established pools. It represents an unrestricted or productive capacity, unencumbered by operating factors. Consequently, future available supply figures for light crude oil should be reduced by about 2 per cent to reflect factors such as plant turnaround, operating problems in the field, or the effect of weather conditions.

The supply forecast of light crude oil from established pools is summarized in Table 3-3. As shown, the productive capacity from existing reserves is expected to decline steadily from 131 x 10^3 m^3/d to 30 x 10^3 m^3/d by 2003. This supply is not expected to be very sensitive to prices since, with the minor exception of some stripper wells, operating revenues will almost always exceed operating costs in the range of prices assumed in this report.

The forecast of supply from remaining established reserves by individual pipeline system is outlined in Appendix B.

3.2.2 Supply from New Discoveries/Additions

Given the prospects for new discoveries of light crude oil, the Board's supply forecasts from undiscovered reserves were based on the medium geological potential of 350 x 10^6 m^3. In preparing the forecast of annual productivity, the Board first prepared an expected profile of reserves additions for the base cases, as illustrated in Figure 3-1. The first 5 years of the profiles were based on the Board's expectations of drilling activity and the corresponding impact on reserves additions. At the projected base price levels, the Board believes that drilling activity would continue at recent high levels before declining in the mid-1990s as opportunities decline. The Board expects the greater part of the remaining undiscovered reserves to be found over the next 15 years.

A revised normalized productivity profile was used to convert reserves additions to annual productivity. Based on a performance review of single and multi-well pools discovered since 1981 and all new wells drilled since then, the Board found that:

- The normalized productivity profile used in ERCB Report 85-A, with a peak capacity of 230 m^3/d per million m^3 of recoverable reserves and a subsequent decline rate of 10 per cent, was generally consistent with the performance of recently discovered pools.

- In order to account for the acceleration effects of infill drilling in existing pools, the normalized profile should be adjusted by increasing the peak capacity to 300 m^3/d per million m^3 of recoverable reserves and by increasing the subsequent decline rate to 15 per cent. The revised profile is illustrated in Figure 3-2.

The predicted productivities from future discoveries/additions for Base Cases 1 and 2 are summarized in Table 3-3. As shown, this represents a significant portion of the total light crude oil supply in future.

3.2.3 Supply from Tertiary Additions

Since 1980, the Board has estimated that in total, some 340×10^6 m^3 of oil would ultimately be recovered through the application of tertiary recovery. After reviewing the performance of all tertiary schemes to date, the Board believes the total ultimate potential to be about 300×10^6 m^3, having regard for the lower incremental recovery expectations in horizontal miscible floods. Some 105×10^6 m^3 of this amount has been recognized as established reserves by year-end 1987, leaving a remaining ultimate potential of about 195×10^6 m^3.

Based on discussions with industry, and given the recent pace of tertiary applications, the Board expects that 10×10^6 m^3 of reserves will be recognized in 1988 and about 5×10^6 m^3 every year thereafter. This reflects a slow but steady pace of development, such that 85×10^6 m^3 of additional reserves (about 40 per cent of the remaining potential) are recognized by 2003.

The normalized productivity profile used to convert tertiary reserves additions to annual productivity is illustrated in Figure 3-2 and is essentially the same as in previous Board reports.

To identify future infill drilling in tertiary schemes, discussions were held with major operators to clarify their plans and to project the likely timing of their developments. Based on the information provided, the Board estimates that:

- An average of 25 infill wells will be drilled each year for the next 5 years. The Board expects that any drilling past this point would likely be in more marginal tertiary candidates with lower rates of production. As well, any benefits from infill drilling could be largely offset by compensating producer to injector conversions.

- The average well will reach a peak rate of 40 m^3/d and produce a total volume of 60 x 10^3 m^3. However, only one-third of this amount was assumed to represent incremental recovery. The remainder will be an acceleration of the base case recovery.

The forecasts of production from tertiary additions are summarized in Table 3.3. As shown, production starts at about 1 x 10^3 m^3/d at the beginning of the forecast, and increases to 7 x 10^3 m^3/d by the end of the forecast.

3.3 HEAVY CRUDE OIL SUPPLY

3.3.1 Supply from Established Pools

Actual production of heavy crude oil in 1987 averaged about 20.6 x 10^3 m^3/d (excluding experimental production of about 1 x 10^3 m^3/d). As illustrated in Figure 2 of Appendix A, the production rate generally increased throughout the year and reached 22.3 x 10^3 m^3/d by December 1987.

The current forecast is based on the performance of all producing pools at year-end 1987. The largest 90 producing pools, representing approximately 80 per cent of the total provincial productivity, were reviewed individually. Unlike the forecast for light crude oil, the Board found that productivity levels and historical decline trends were such that major reserves increases were necessary in numerous pools. Overall, the remaining established reserves for heavy crude oil were increased by about 50 per cent, thereby increasing the total average recovery factor for heavy crude oil from 11 to 13 per cent. These adjustments were necessary because current productivity, combined with expected decline rates, was incompatible with year-end remaining recoverable reserves. The Board forecast of supply from remaining established reserves by individual pipeline system is outlined in Appendix B.

The forecast shown in Appendix B predicts the supply of heavy oil from established pools to decline at an average annual rate of about 10 per cent over the next 10-year period, which is higher than the observed decline rate of 7 per cent in recent years. The Board reviewed the average well performance of heavy crude oil since 1981 and found that recent shallow decline rates could be largely attributed to a general trend of increasing average well fluid rates. The decline rate would have been approximately 10 per cent on an annual basis if the average well fluid rate had remained constant.

Based on this information the Board adjusted the overall heavy crude oil forecast to be more consistent with recently observed decline trends. It was assumed that improvements in overall fluid handling capacity would continue and would reach a peak within approximately 5 years. Thereafter, the productivity decline rate would accelerate such that the reserves used in the forecast would ultimately be achieved.

The adjusted supply forecast of heavy crude oil from established pools is summarized in Table 3-4. As with light crude oil, there is virtually no difference between heavy crude oil supply under the assumed base case price forecasts. Supply is expected to average 20 x 10^3 m^3/d in 1989, and gradually decline to 4 x 10^3 m^3/d by the end of the forecast.

3.3.2 Supply from New Discoveries/Additions

The Board based its forecast of new discoveries of heavy oil on the medium geological potential of 115 x 10^6 m^3 identified in Section 3.1.2. This reflects a significant increase from that previously recognized by the Board.

Considering the economic outlook assumed in the base cases, the Board believes that industry activity would proceed at a relatively fast pace. The corresponding reserves additions that could reasonably be expected are illustrated in Figure 3-4. As shown, reserves additions would average 10 x 10^6 m^3/yr over the next 5 years and then decline. The first 5 years of the profiles were based on a continuation of recent drilling activity. The Board found that recent estimates of reserves additions due to new drilling were lower than expected, and recovery factors were higher than expected because of the density of drilling. The Board expects much of the remaining ultimate potential in the base cases to be found by the end of the forecast period.

Based on a review similar to light crude oil, a revised normalized productivity profile was generated to convert reserves additions to annual productivity. The revised profile is illustrated in Figure 3-5. It shows that new discoveries will reach a peak rate of 250 m^3/d per million m^3 of recoverable reserves in the second year of production and then decline at a rate of 10 per cent per year.

The forecasts of productivity from future discoveries/additions are summarized in Table 3-4. As shown, supply is expected to increase gradually and add some 12 to 13 x 10^3 m^3/d by the mid-1990s. This activity represents a significant portion of the total heavy crude oil supply in the future.

3.3.3 Supply from Tertiary/Experimental Additions

To forecast enhanced recovery activity in the heavy oil sector, the Board relied extensively on its discussions with industry. Major operators confirmed the Board's view that the short- to medium-term outlook for commercial tertiary schemes in conventional heavy crude oil pools does not appear to be promising. Consequently, as illustrated in Figure 3-6, the Board has assumed small reserves additions in this category, commencing in 1995, such that 9×10^6 m^3 of potential reserves are recognized by 2003.

The normalized productivity profile used to convert reserves additions to annual productivity is illustrated in Figure 3-5 and remains unchanged from previous reports.

The current supply from experimental schemes, approximately 1×10^3 m^3/d, is expected to continue until 1995, when they are gradually reduced to minimal levels.

As shown in Table 3-4, the Board expects the overall contribution of tertiary/experimental productivity to the total heavy crude oil supply to be quite small.

TABLE 3-1 SUMMARY OF ULTIMATE POTENTIAL UNDISCOVERED RESERVES - LIGHT CRUDE OIL
Effective 31 December 1987
(millions of cubic metres)

	Period	Geological Potential		
		Lower	Medium	Upper
UNDISCOVERED OIL IN PLACE (millions of cubic metres)				
	Upper Cretaceous	215	240	330
	Lower Cretaceous	245	285	350
	Jurassic/Triassic /Mississippian	160	195	260
	Devonian	560	650	835
	Other	20	30	45
	Total	1 200	1 400	1 820
EXPECTED AVERAGE RECOVERY FACTOR		0.25	0.25	0.25
UNDISCOVERED ULTIMATE POTENTIAL		300	350	450

TABLE 3-2 SUMMARY OF ULTIMATE POTENTIAL UNDISCOVERED RESERVES - HEAVY CRUDE OIL
Effective 31 December 1987
(millions of cubic metres)

	Geological Potential		
	Lower	Medium	Upper
UNDISCOVERED OIL IN PLACE			
Lloydminster Area	500	600	800
Other Areas	320	375	500
Total	820	975	1 300
EXPECTED AVERAGE RECOVERY FACTOR	0.12	0.12	0.12
UNDISCOVERED ULTIMATE POTENTIAL	100	115	155

TABLE 3-3 FORECAST OF LIGHT CRUDE OIL SUPPLY
1988 - 2003
Base Case 1 and Base Case 2
(thousands of cubic metres per day[a])

	1	2	3	4	5	6	7	8
Year	Base Case 1				Base Case 2			
	Established Reserves	Discoveries /Additions	Tertiary	Total	Established Reserves	Discoveries /Additions	Tertiary	Total
1988	131	6	1	138	131	5	1	137
1989	120	17	2	139	120	14	2	137
1990	108	26	4	138	108	22	4	134
1991	97	34	5	135	97	29	5	130
1992	87	39	5	131	87	33	5	125
1993	77	43	6	126	77	36	6	119
1994	70	45	5	119	70	38	5	112
1995	63	45	4	113	63	39	4	106
1996	57	45	5	106	57	38	5	100
1997	52	44	5	101	52	38	5	94
1998	47	43	5	95	47	37	5	89
1999	43	41	6	90	43	35	6	84
2000	39	39	6	84	39	34	6	79
2001	36	37	6	79	36	32	6	74
2002	33	35	7	74	33	30	7	70
2003	30	33	7	70	30	28	7	65

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[a] Columns may not add due to rounding.

TABLE 3-4 FORECAST OF HEAVY CRUDE OIL SUPPLY
1988 - 2003
Base Case 1 and Base Case 2
(thousands of cubic metres per day[a])

	1	2	3	4	5	6	7	8	9	10
Year	Base Case 1					Base Case 2				
	Established Reserves	Discoveries /Additions	Tertiary	Experimental	Total	Established Reserves	Discoveries /Additions	Tertiary	Experimental	Total
1988	21	1	-	1	24	21	1	-	1	24
1989	20	4	-	1	25	20	3	-	1	24
1990	19	7	-	1	26	19	6	-	1	25
1991	17	9	-	1	27	17	7	-	1	26
1992	16	11	-	1	27	16	9	-	1	26
1993	14	12	-	1	27	14	11	-	1	26
1994	13	13	-	1	27	13	11	-	1	25
1995	11	13	*	1	26	11	12	*	1	24
1996	10	13	*	1	24	10	12	*	1	23
1997	9	13	1	*	23	9	12	1	*	22
1998	7	13	1	*	21	7	12	1	*	20
1999	6	12	1	*	20	6	11	1	*	19
2000	6	12	2	*	19	6	11	2	*	18
2001	5	12	2	*	18	5	11	2	*	18
2002	4	11	2	*	17	4	11	2	*	17
2003	4	11	2	*	16	4	10	2	*	16

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[a] Columns may not add due to rounding.

* Less than 500 m^3 per day.

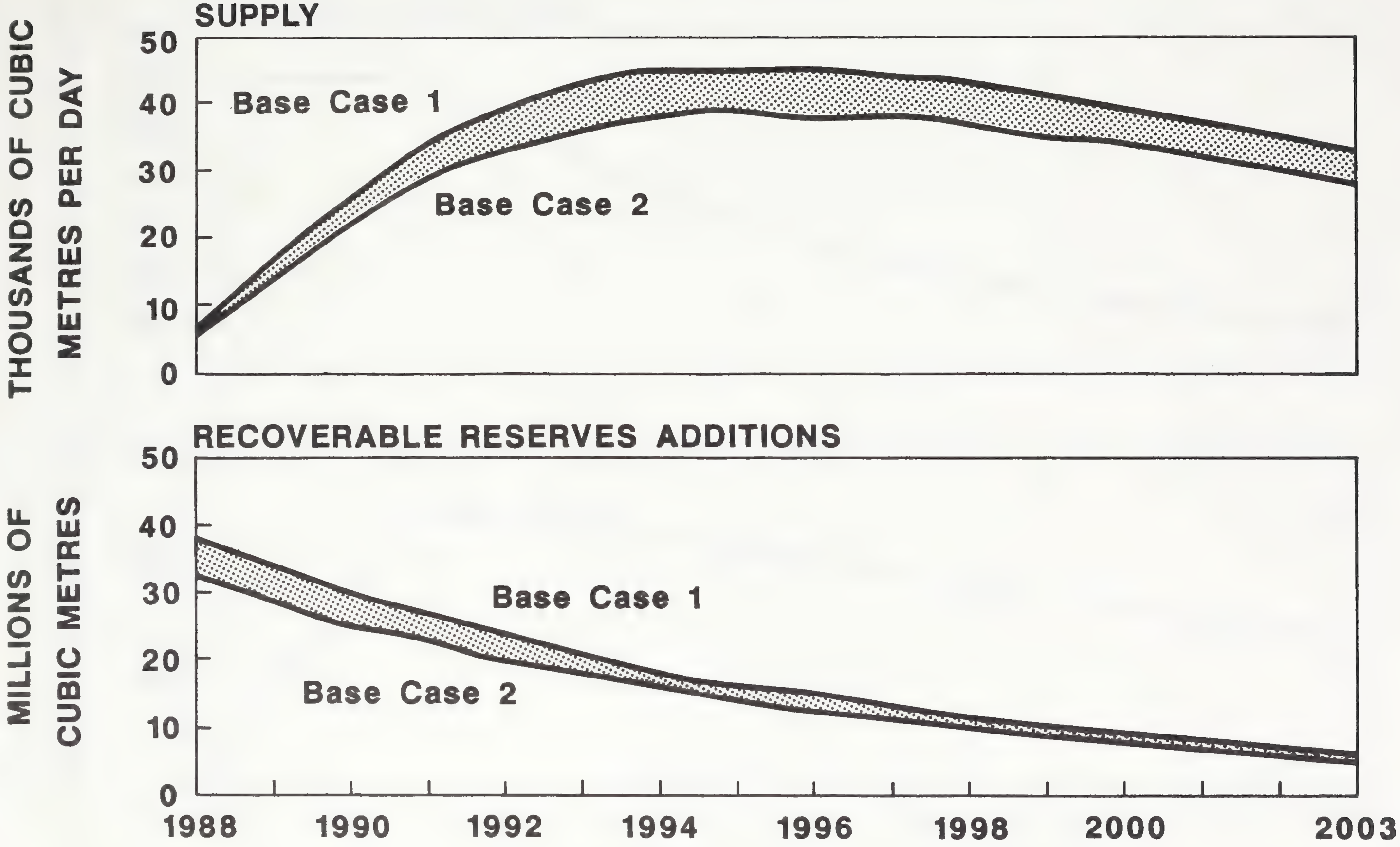

FIGURE 3–1 RESERVES GROWTH AND SUPPLY FROM DISCOVERIES/ADDITIONS
LIGHT CRUDE OIL

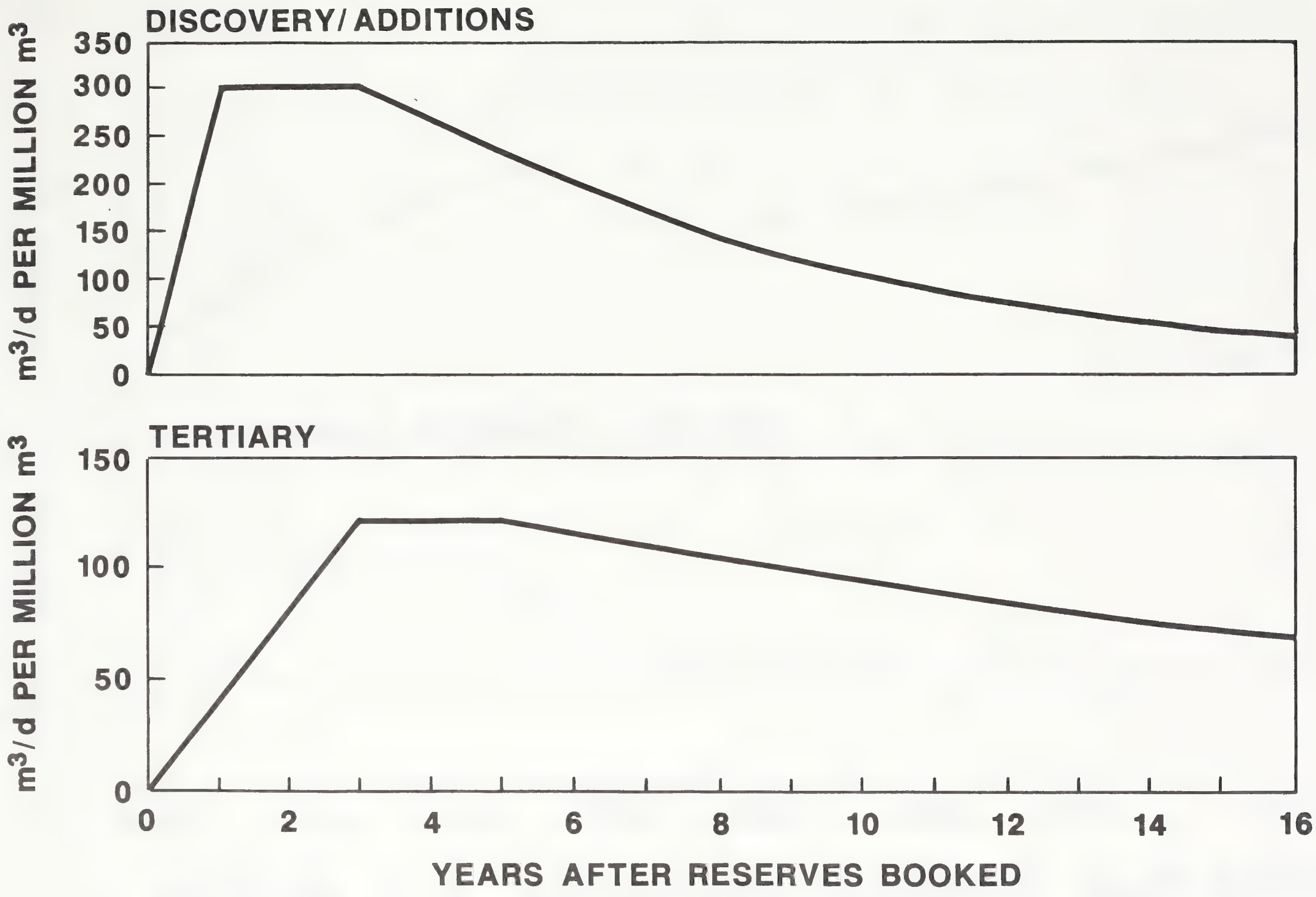

FIGURE 3–2 NORMALIZED PRODUCTIVITY PROFILES
LIGHT CRUDE OIL

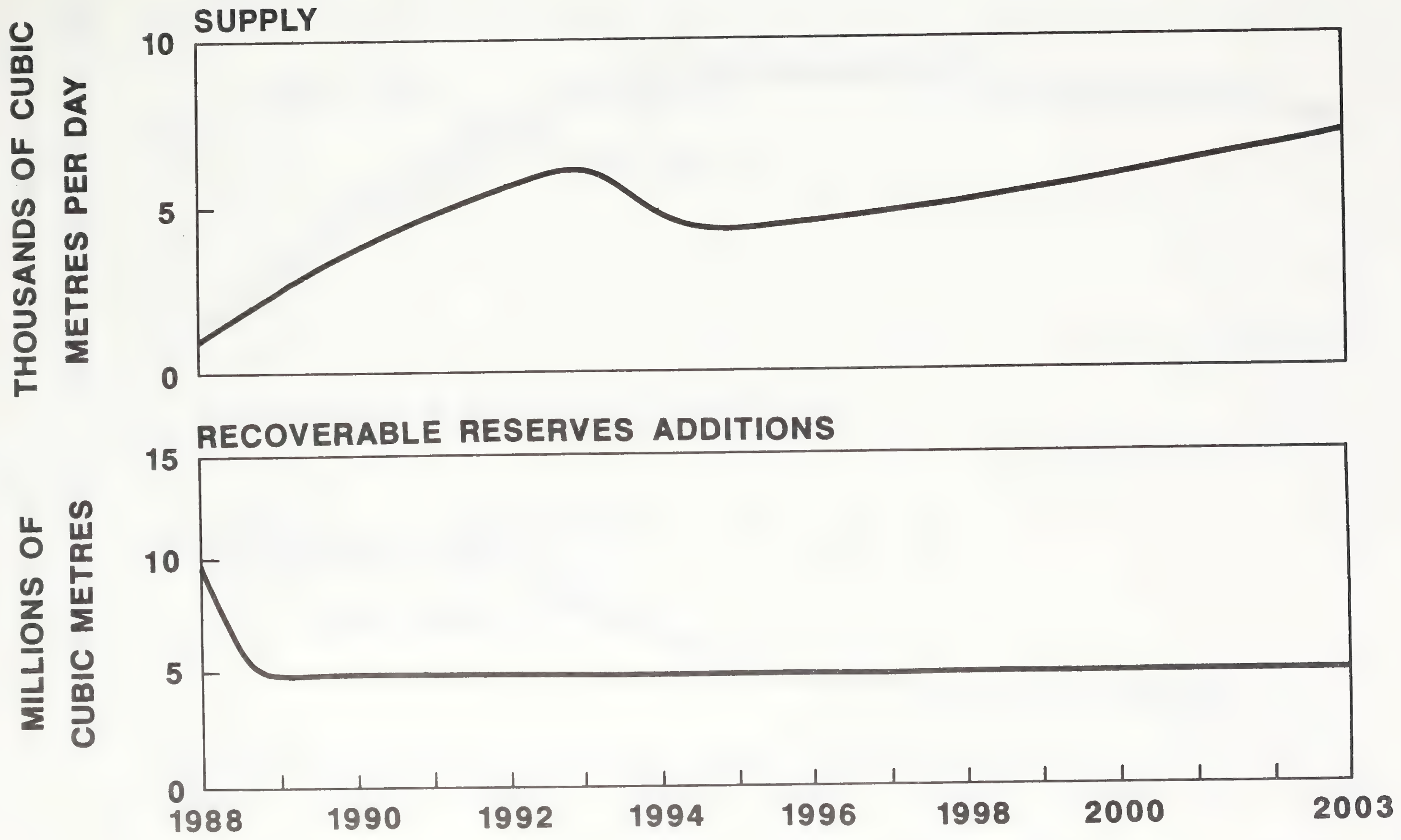

FIGURE 3-3 RESERVES GROWTH AND SUPPLY FROM TERTIARY ADDITIONS
LIGHT CRUDE OIL

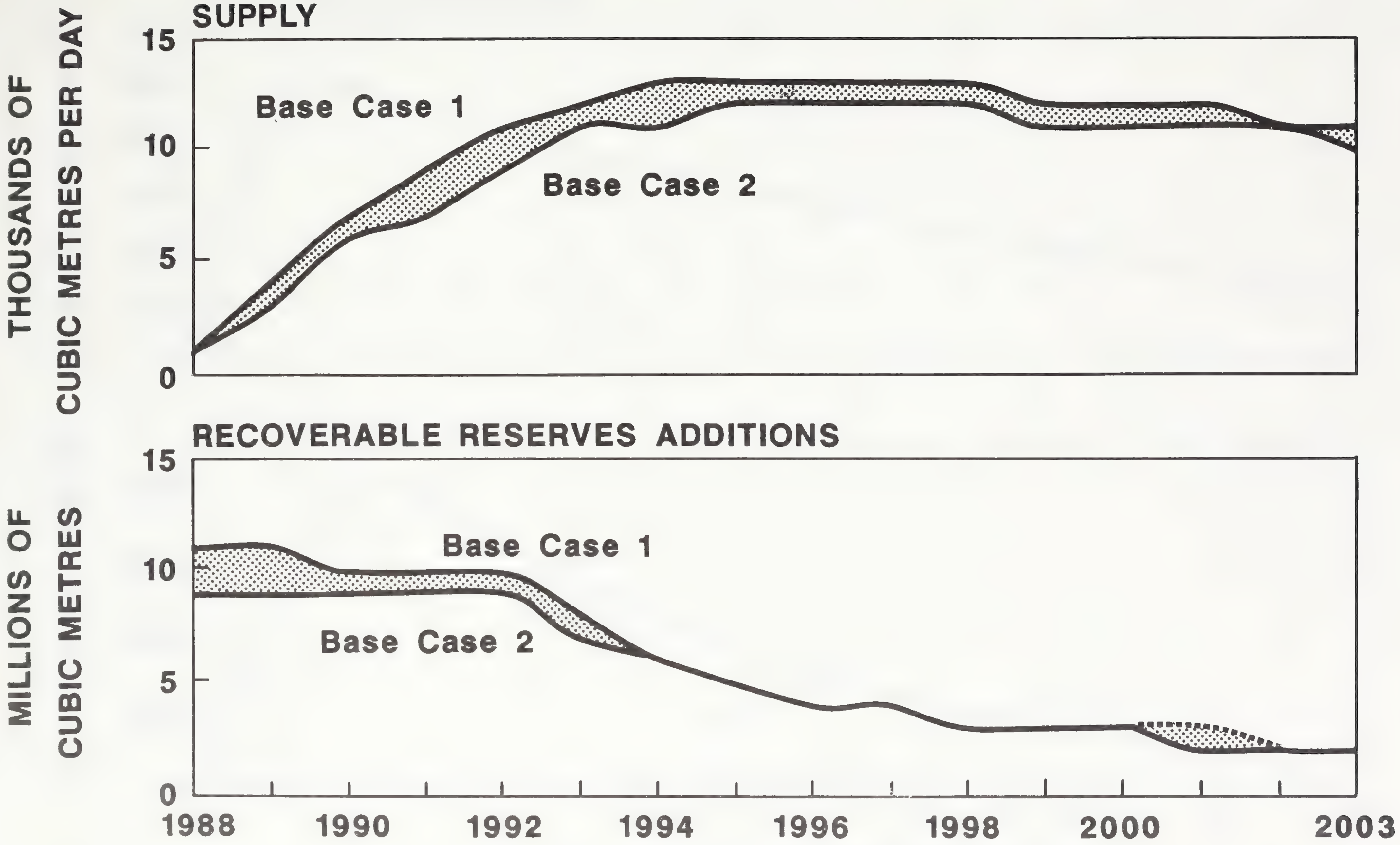

FIGURE 3–4 RESERVES GROWTH AND SUPPLY FROM DISCOVERIES/ADDITIONS
HEAVY CRUDE OIL

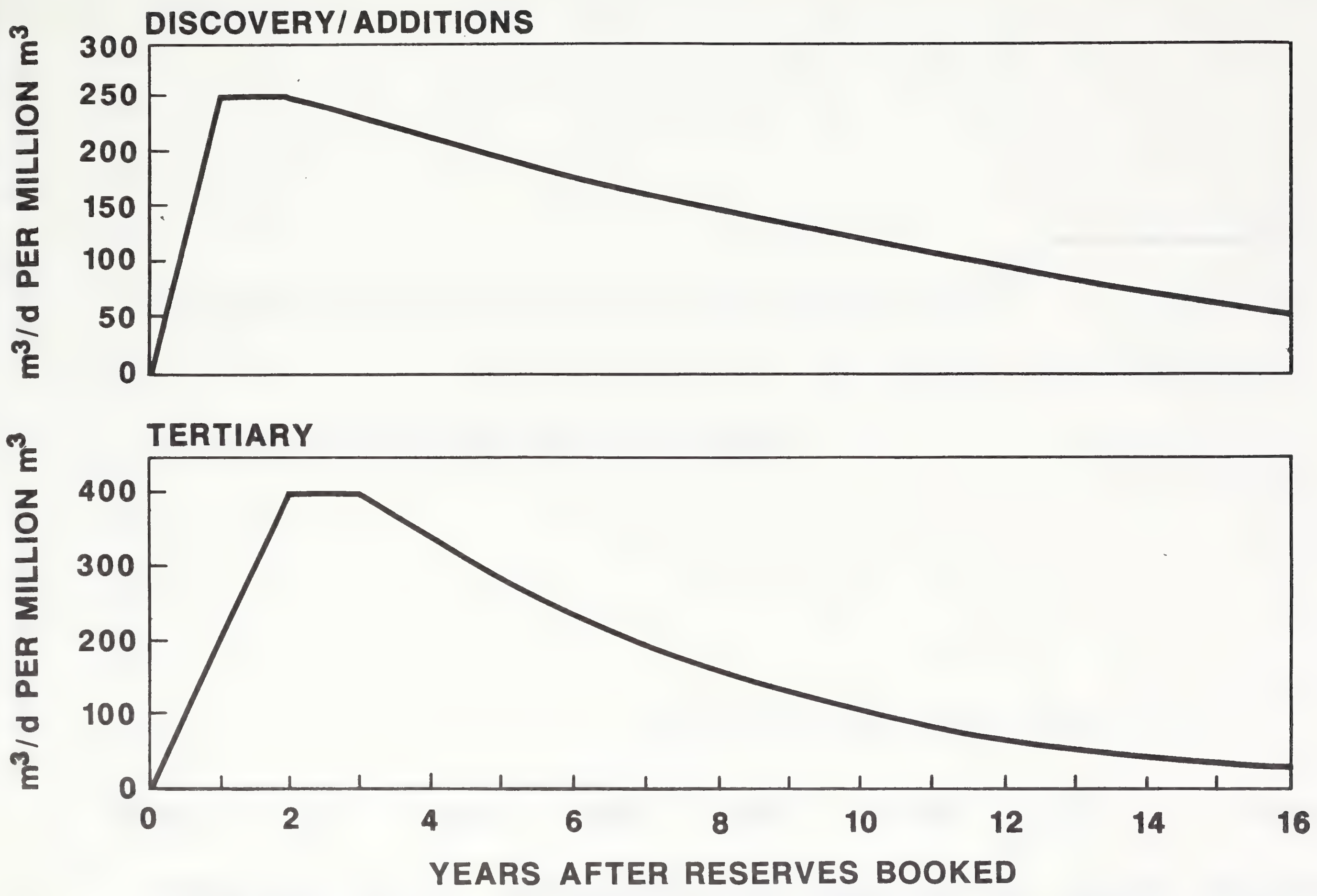

FIGURE 3–5 NORMALIZED PRODUCTIVITY PROFILES
HEAVY CRUDE OIL

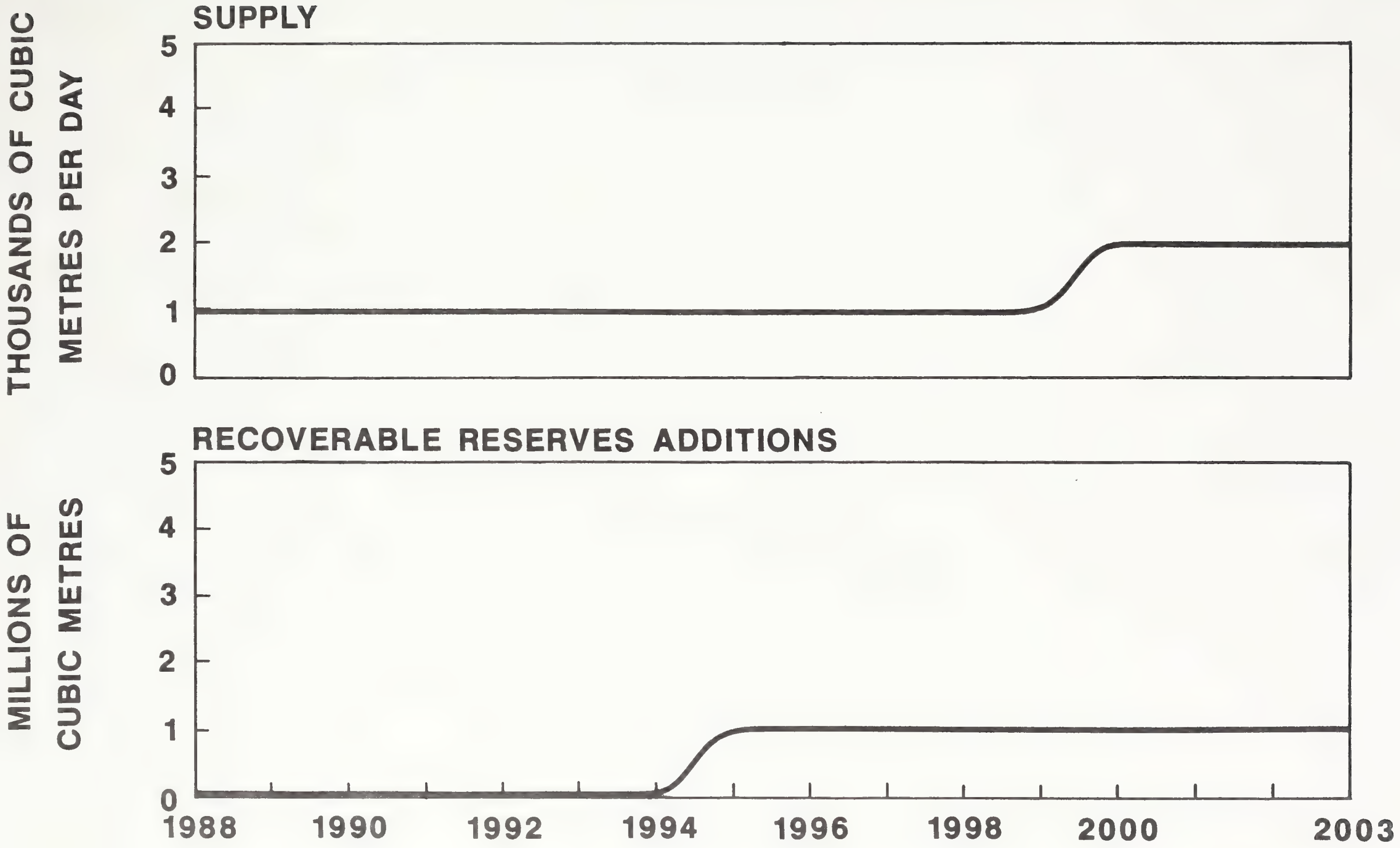

FIGURE 3-6 RESERVES GROWTH AND SUPPLY FROM TERTIARY/EXPERIMENTAL ADDITIONS
HEAVY CRUDE OIL

4 PENTANES PLUS SUPPLY

4.1 ULTIMATE POTENTIAL

The "future portion" of the ultimate potential for pentanes plus is the product of two factors: the volume of gas yet to be discovered and the anticipated pentanes plus content of such gas. The Board has recently completed an internal review of both these factors.

In ERCB Report 79-G, the Board concluded that the ultimate potential for marketable gas was in the range of 3.7 to 3.9 x 10^{12} m^3 but noted that, given improvements in economic and/or technological conditions, the ultimate potential could be in excess of 5.6 x 10^{12} m^3. Given the significant growth in gas reserves which has been realized in the past 10 years, despite a rather modest amount of drilling activity, the Board adopted an ultimate potential of 4.2 x 10^{12} m^3 in 1985, and increased it again in 1987 to its current level of 4.8 x 10^{12} m^3. Notwithstanding these adjustments, the Board continues to recognize that, given significant improvements in economic conditions and technology, the ultimate potential for gas could be substantially higher.

The pentanes plus content of future gas discoveries, the second factor influencing the ultimate potential for pentanes plus, has been periodically reviewed by the Board in recent years and was discussed in ERCB Reports 81-B, 83-E, and 85-A. Such reviews have focused on the pentanes plus-to-gas ratio on both a production and reserves basis. These ratios have shown steady declines during the past 10 to 15 years.

Consequently, the Board had adopted a conservative estimate of the future pentanes plus-to-gas ratio of 65 cubic metres per million cubic metres of gas for the purposes of estimating the ultimate potential of pentanes plus.

However, in light of the recent discovery of a major gas pool containing significant volumes of natural gas liquids, the Caroline Beaverhill Lake A Pool (Caroline Pool), and in view of recent indications that the decline in the pentanes plus-to-gas ratio in both production and reserves is reversing, the Board conducted a more detailed review of its forecasts.

With this review the Board also adopted a new methodology to calculate the reserves potential. The province was divided into areas which are geologically similar and within which the gas reserves discovered to date are a significant portion of those likely to be found. The co-products (sulphur, pentanes plus, etc) content of the gas found to date was calculated for each area. It was assumed that future discoveries in each of the areas will have co-product contents similar to the established reserves. In this manner the average co-products content of all future reserves was calculated.

The Board's analysis suggests that the trend toward gas with a lower pentanes plus content will reverse and that future discoveries will be similar to that of the initial established reserves in the province. Consequently, the Board selected a ratio of 85 cubic metres of pentanes plus per million cubic metres of gas. Although this ratio is somewhat lower than that suggested by the analysis, it was chosen because of the uncertainty in predicting the properties and extent of gas yet to be discovered.

Applying this ratio to the Board's estimate of future gas discoveries, and adding this to the initial established reserves, yields an ultimate potential for pentanes plus of 430 x 10^6 m^3. This represents an increase of 34 per cent over the previous Board forecast. The pentanes plus reserves and cumulative production data are summarized in Table 1 (see Executive Summary).

4.2 GAS PRODUCTION

The Board anticipates a steady growth in gas consumption in Alberta, as discussed in ERCB Report 88-C. A modest but steady growth is similarly anticipated in other Canadian markets. The Board also expects that the recent substantial growth in U.S. demand for Alberta gas will continue into the 1990s, limited primarily by pipeline capacity. Given the Board's current estimate of the ultimate potential for gas, as discussed in Section 4.1, Alberta's annual gas production is expected to level off at about 107×10^9 m^3 through the mid-1990s and to begin to decline early in the next century.

To assess the province's ability to meet the forecast markets for gas, the Board used its own data base and a deliverability model. The model predicts the producibility of all established gas reserves on the basis of reservoir and test data. It does the same for future reserves on the basis of judgemental assumptions respecting reserve development rates and reservoir characteristics.

In the first few years of the forecast, the Board expects all gas production to come from established reserves. Within a few years, reserves not presently discovered can be expected to take on a signficant role in Alberta's total gas production. In 20 years, more than one-half the total production is expected to come from future reserves.

The Board's forecast of gas production from both established and future reserves is shown in Table 4-1.

The Board notes that in some pools, such as the recently discovered Caroline Pool, natural gas liquids recovery represents a very significant portion of the overall revenue from production and is, therefore, a major consideration in the production strategy applied to the pool. However, such pools are the exception and pentanes plus recovery is a rather minor consideration in recovering the total resource in most pools. Consequently, the demand for gas and the producers' contractual situation respecting gas governs much of the pentanes plus production in the province.

4.3 PENTANES PLUS FROM ESTABLISHED RESERVES

For currently connected reserves, the Board's deliverability model yields forecasts of pentanes plus expected to be recovered at existing plants, having regard for the pools producing to and the recovery efficiencies of such plants. The deliverability model is also used for unconnected reserves, but plant recovery efficiencies were estimated based on gas analyses for the reserves.

The Board's forecast of pentanes plus production from established reserves is shown in column 4 of Table 4-1. As production of natural gas from established pools increases in the coming years, production of pentanes plus is expected to increase somewhat through the early 1990s, to slightly more than 20 x 10^3 m^3/d. This is largely due to the impact of the proposed Caroline development. Supply from established reserves are likely to decline throughout the remainder of the forecast. By the end of the forecast period, production from established reserves is expected to amount to some 11 x 10^3 m^3/d.

4.4 PENTANES PLUS FROM FUTURE RESERVES

The Board's forecast of pentanes plus available from future gas discoveries has been generated by applying the ratio of 85 cubic metres of pentanes plus per million cubic metres of gas for future reserves, as discussed in Section 4.1, to its forecast of future gas production shown in column 2 of Table 4-1. As shown in column 5 of Table 4-1, the Board expects pentanes plus production from future gas discoveries to increase to 10 x 10^3 m^3/d by the end of the forecast.

4.5 TOTAL PENTANES PLUS SUPPLY

The Board's forecast of total pentanes plus supply is shown in Figure 4-1 and in column 6 of Table 4-1. Production is expected to increase to some 22 x 10^3 m^3/d by the early 1990s and to remain at about this level for nearly 10 years. With the Board's current estimates of ultimate potential for gas and pentanes plus, production is anticipated to begin to decline early in the next century.

In preparing its forecast of pentanes plus, the Board has not presented the supply impact of alternative price scenarios as has been done for oil. The Board does not expect gas prices to track oil prices in a predictable manner in the near term. It does anticipate, however, that the strong demand for gas will maintain a high level of activity and stable and growing prices for gas. Further, it notes that a significant portion of the pentanes plus production in Alberta is produced from pools which are either not very sensitive to gas demand fluctuation, or which are preferentially produced even at low gas demand.

Certainly, variation of the ultimate potential for gas and pentanes plus from that estimated by the Board would serve to change the long-term availability of pentanes plus. Such scenarios could be generated rather easily by applying the pentanes plus-to-gas ratio for future gas to variations of the future gas production forecast.

TABLE 4-1 FORECAST OF MARKETABLE GAS PRODUCTION AND PENTANES PLUS SUPPLY
1988 - 2003
(Gas: millions of cubic metres per day @ 37.4 MJ/m^3)
(Pentanes plus: thousands of cubic metres per day)

	1	2	3	4	5	6
Year	Gas			Pentanes Plus		
	Established	Discoveries /Additions	Total	Established	Discoveries /Additions	Total
1988	240	0	240	18	0	18
1989	245	0	245	19	0	19
1990	246	4	250	19	0	20
1991	254	6	260	20	1	20
1992	255	13	268	21	1	22
1993	255	20	274	21	2	22
1994	253	29	282	20	2	22
1995	250	38	288	19	3	22
1996	244	48	292	18	4	22
1997	233	59	292	17	5	22
1998	222	70	292	16	6	22
1999	210	82	292	15	7	22
2000	199	92	290	14	8	22
2001	185	100	285	14	9	22
2002	162	112	275	12	10	22
2003	141	118	259	11	10	21

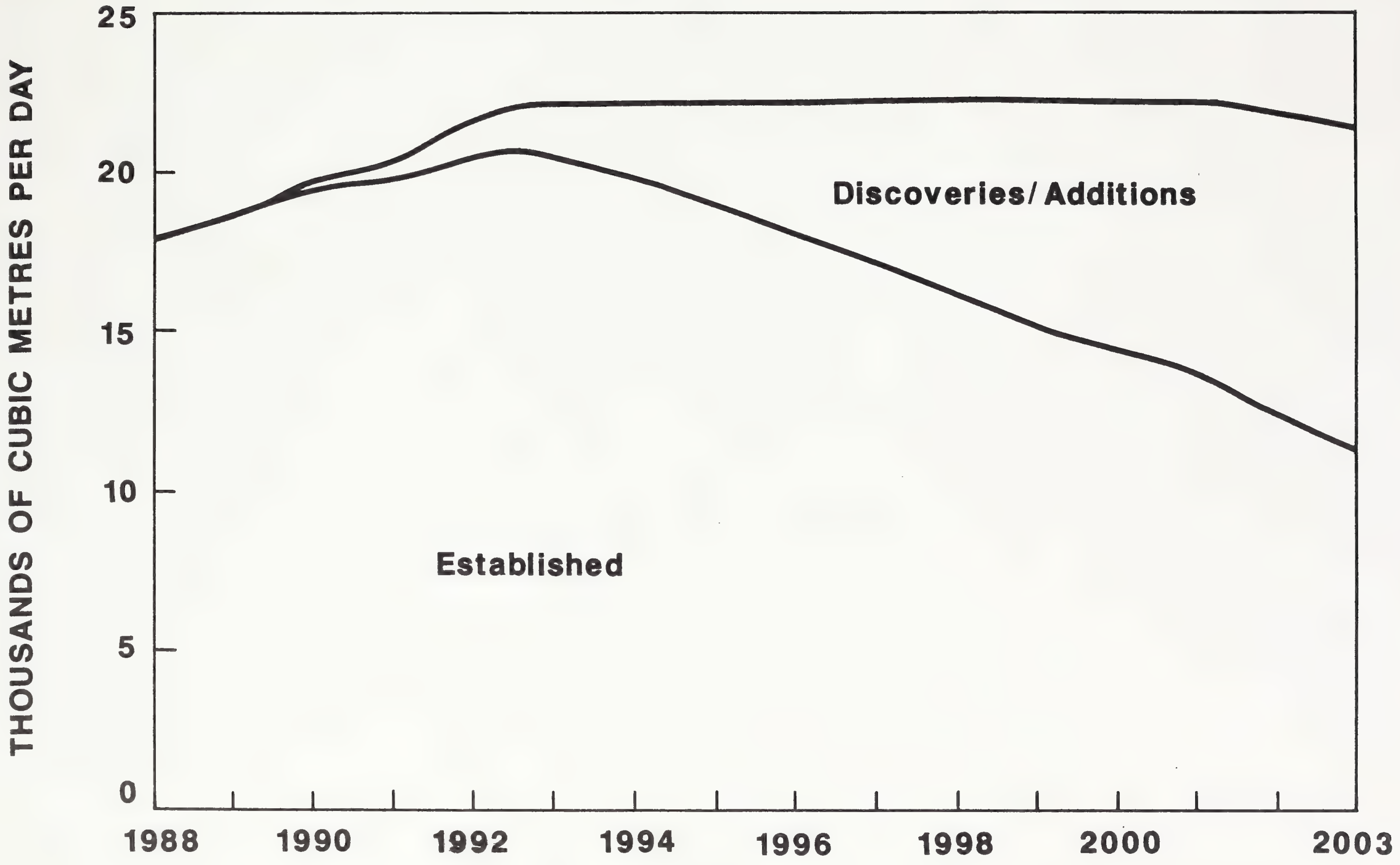

FIGURE 4–1 TOTAL SUPPLY OF PENTANES PLUS

5 CRUDE BITUMEN AND SYNTHETIC CRUDE OIL SUPPLY

The pattern of development under each of the price scenarios was predicated on an assessment of information provided by operators and, to some extent, on the results of the Board's economic analysis of the most promising development sites in Alberta. In general, oil sands developments are expected to be much more sensitive to economic conditions than activity in the conventional oil industry.

5.1 CRUDE BITUMEN

The supply of crude bitumen, as shown in Tables 5-1 and 5-2 and in Figure 5-1, was based, in part, on an assessment of the most likely development plans for oil sands leases, identified by the operators. The assessment included an in-house technical review of the lease productive capability in relation to the proposed development technology. In addition, an economic analysis of a representative project was conducted to help predict the impact of each of the price scenarios on the timing of development. The impacts of each of the price scenarios on the representative project were used as proxies for other proposed projects and expansions, for which there was not enough detailed information for a complete economic analysis.

In the Base Case 1 forecast considerable growth in the supply of crude bitumen would occur for the next 10 years, as an early scheduling of new plants and expansions would be expected under this price scenario. A reasonable rate of return was obtained for a full-scale development of the representative project. Thus, the Base Case 1 forecast essentially represents a full-development case. This optimistic forecast is not expected to be achieved without a concomitant expansion in North American upgrading and pipeline capacities, and/or continued growth in exports to offshore markets. The current pipeline-connected North American market for Canadian heavy oil is about 80 x 10^3 m^3/d, and may be constrained by a diluent shortage in the late 1990s.

Moderate growth would occur under the Base Case 2 price scenario. In general, the expansion plans of existing commercial projects would not be expected to differ significantly between the two base cases over the short term (2 to 3 years). Reduced cash flow and financial viability would be expected to delay some development plans in the long term, however. In the Base Case 2 scenario a reasonable rate of return was obtained for a scaled-down development of the representative project. Market constraints could also have an impact on the timing of some developments.

Under both price forecasts non-upgraded bitumen production averages 32 x 10^3 m^3/d in 1990. In the Base Case 1 scenario, crude bitumen production peaks at 65 x 10^3 m^3/d in 1998, and declines somewhat with the introduction of a bitumen upgrader. Under the Base Case 2 forecast, crude bitumen reaches 46 x 10^3 m^3/d by the end of the forecast.

5.2 SYNTHETIC CRUDE OIL

The Board's forecasts of total SCO production are shown in Tables 5-1 and 5-2 and in Figure 5-2. A similar methodology to that of the crude bitumen forecast was used. Both SCO forecasts assume Syncrude's recently completed Capacity Addition Project (CAP) will bring its total SCO production to 25 x 10^3 m^3/d by 1991, with an improvement in the yield of SCO from bitumen of approximately 2 to 5 per cent. Each forecast also assumes that Suncor will complete a debottlenecking program and increase its upgrading capacity to 11.6 x 10^3 m^3/d by 1993.

Differences between the two forecasts arise from the expected impact each price scenario would have on the timing of OSLO, Syncrude and Suncor expansions, and an upgrader. A 5-year construction period prior to the phase-in of production is assumed for all plants and expansions. To reflect capital, engineering, and manpower constraints that would likely occur if all projects (including major projects outside Alberta) proceeded concurrently, a staggering of project start-up dates has been incorporated.

The yield of synthetic crude oil from bitumen is dependent on the upgrading technology used. The Board expects OSLO and other future projects will use high-yield hydrogen addition upgrading technology which is expected to achieve a yield of approximately 100 per cent. Following its expansion, Syncrude is expected to achieve yields in the 92 to 95 per cent range. This compares with the current project yield of 81 to 84 per cent range.

A new bitumen upgrader was assumed to be built in both forecasts. In general, the timing for the construction of the upgrader was expected to be a function of the price differential between light and heavy crude oil, although other factors could influence the timing of the development. A differential of approximately \$45 US/m^3 (\$7/bbl) between heavy and light was assumed to be the commercial threshold necessary for construction of an upgrader. From production levels of 33 x 10^3 m^3/d in 1990 under the Base Cases 1 and 2 price forecasts, SCO production reaches about 73 x 10^3 m^3/d under each case, albeit with a more gradual increase under the Base Case 2 scenario.

TABLE 5-1 FORECAST OF CRUDE BITUMEN PRODUCTION
AND SYNTHETIC CRUDE OIL SUPPLY
1988 - 2003
Base Case 1
(thousands of cubic metres per day)

Year	1 Gross Bitumen	2 Synthetic Crude Oil	3	4	5 Non-upgraded Bitumen
		Mining	In Situ	Total	
1988	62	31	-	31	23
1989	65	32	-	32	26
1990	72	33	-	33	32
1991	76	34	-	34	35
1992	83	36	-	36	41
1993	91	36	-	36	47
1994	101	38	-	38	55
1995	107	41	-	41	59
1996	114	46	-	46	61
1997	123	54	-	54	63
1998	130	58	-	58	65
1999	139	64	2	66	65
2000	141	65	4	69	63
2001	142	67	4	71	62
2002	143	67	5	72	62
2003	144	67	6	73	61

TABLE 5-2 FORECAST OF CRUDE BITUMEN PRODUCTION
AND SYNTHETIC CRUDE OIL SUPPLY
1988 - 2003
Base Case 2
(thousands of cubic metres per day)

Year	1 Gross Bitumen	2 Synthetic Crude Oil Mining	3 Synthetic Crude Oil In Situ	4 Synthetic Crude Oil Total	5 Non-upgraded Bitumen
1988	61	31		31	23
1989	65	32	-	32	26
1990	71	33	-	33	32
1991	74	34	-	34	33
1992	76	36	-	36	33
1993	76	36	-	36	33
1994	76	37	-	37	32
1995	79	38	-	38	34
1996	82	39	-	39	37
1997	89	44	-	44	38
1998	100	50	-	50	42
1999	110	59	-	59	44
2000	120	65	2	67	44
2001	125	67	4	71	45
2002	126	67	5	72	45
2003	127	67	5	72	46

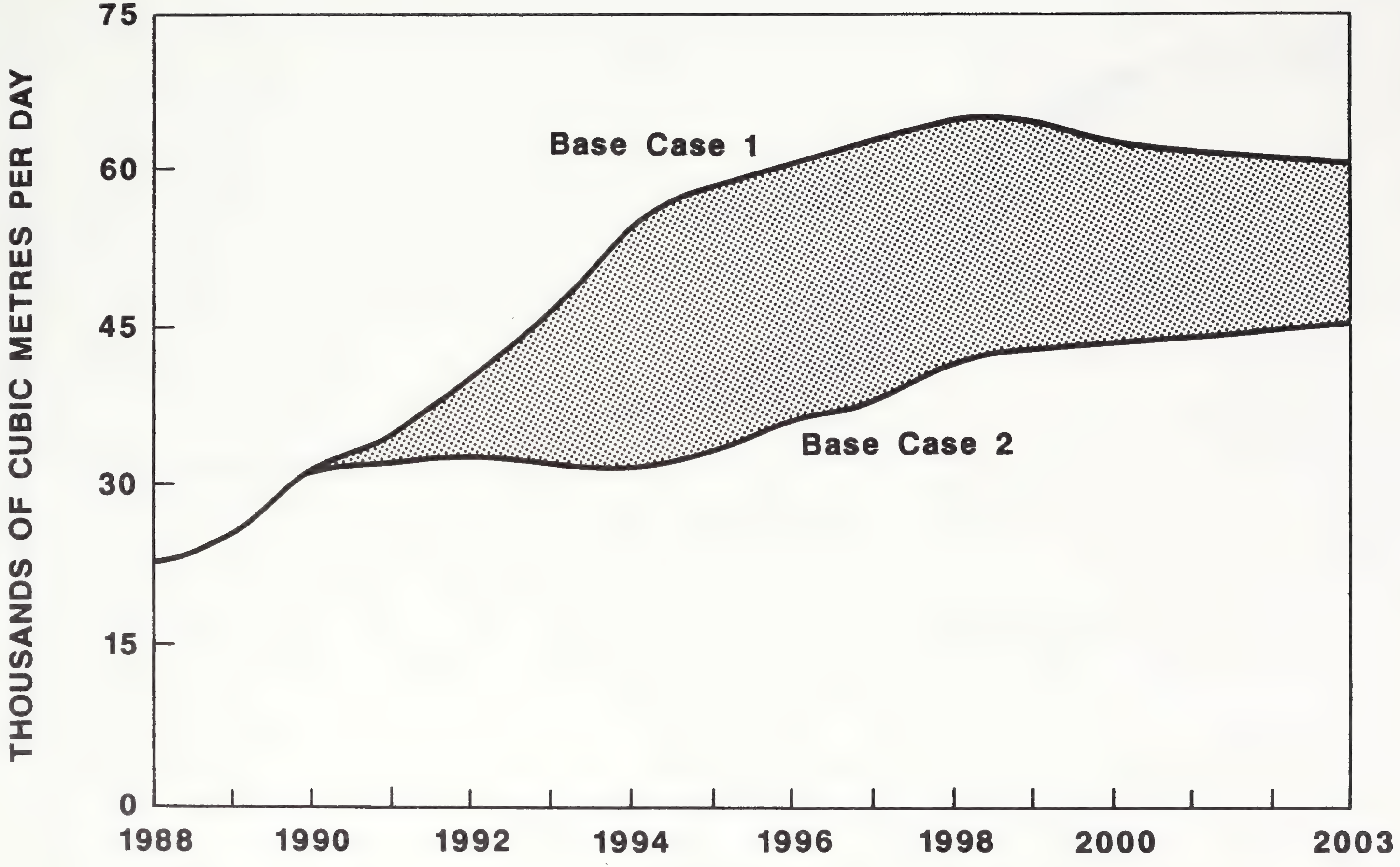

FIGURE 5–1 TOTAL SUPPLY OF BITUMEN

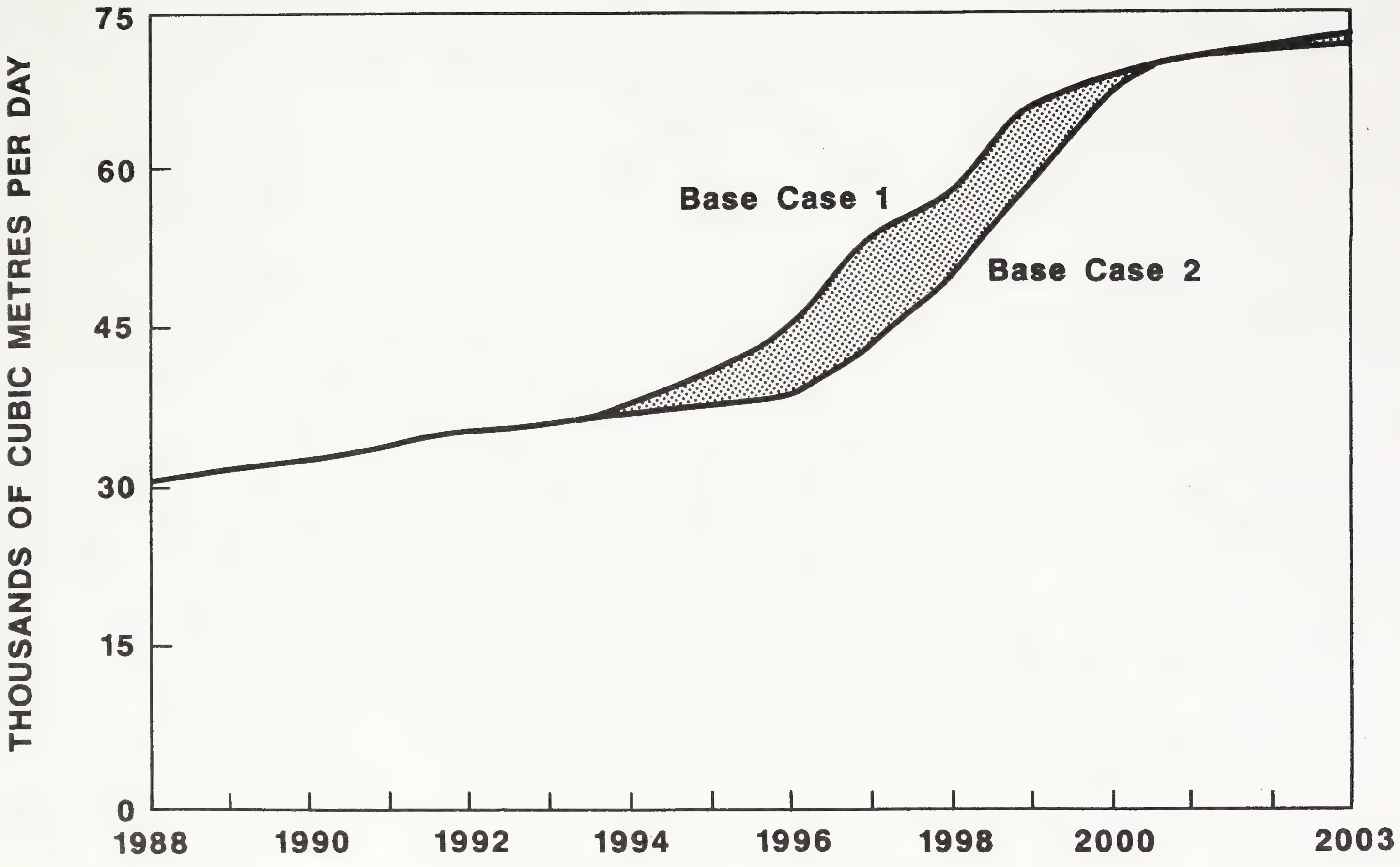

FIGURE 5-2 TOTAL SUPPLY OF SYNTHETIC CRUDE OIL

6 TOTAL CRUDE OIL AND EQUIVALENT SUPPLY

The Board's forecasts of total crude oil and equivalent supply for the base cases over the 1988 - 2003 forecast period are outlined by product in Tables 6-1 and 6-2 and are shown graphically in Figures 6-1 and 6-2.

Total supply in Base Cases 1 and 2 remains quite stable. The declines in conventional crude oil production later in the forecast period are nearly offset by increases in bitumen and synthetic crude oil production. Total supply is maintained above 200 x 10^3 m^3/d.

TABLE 6-1 FORECAST OF TOTAL CRUDE OIL AND EQUIVALENT SUPPLY - ALL PRODUCTS
Base Case 1
(thousands of cubic metres per day)

Year	1 Light	2 Heavy	3 Pentanes Plus	4 Synthetic	5 Non-upgraded Bitumen	6 Total
1988	138	24	18	31	23	234
1989	139	25	19	32	26	241
1990	138	26	20	33	32	249
1991	135	27	20	34	35	251
1992	131	27	22	36	41	257
1993	126	27	22	36	47	258
1994	119	27	22	38	55	261
1995	113	26	22	41	59	261
1996	106	24	22	46	61	259
1997	101	23	22	54	63	263
1998	95	21	22	58	65	261
1999	90	20	22	66	65	263
2000	84	19	22	69	63	257
2001	79	18	22	71	62	252
2002	74	17	22	72	62	247
2003	70	16	21	73	61	241

TABLE 6-2 FORECAST OF TOTAL CRUDE OIL AND EQUIVALENT SUPPLY - ALL PRODUCTS
Base Case 2
(thousands of cubic metres per day)

	1	2	3	4	5	6
Year	Light	Heavy	Pentanes Plus	Synthetic	Non-upgraded Bitumen	Total
1988	137	24	18	31	23	233
1989	137	24	19	32	26	238
1990	134	25	20	33	32	244
1991	130	26	20	34	33	243
1992	125	26	22	36	33	242
1993	119	26	22	36	33	236
1994	112	25	22	37	32	228
1995	106	24	22	38	34	224
1996	100	23	22	39	37	221
1997	94	22	22	44	38	220
1998	89	20	22	50	42	223
1999	84	19	22	59	44	228
2000	79	18	22	67	44	230
2001	74	18	22	71	45	230
2002	70	17	22	72	45	226
2003	65	16	21	72	46	220

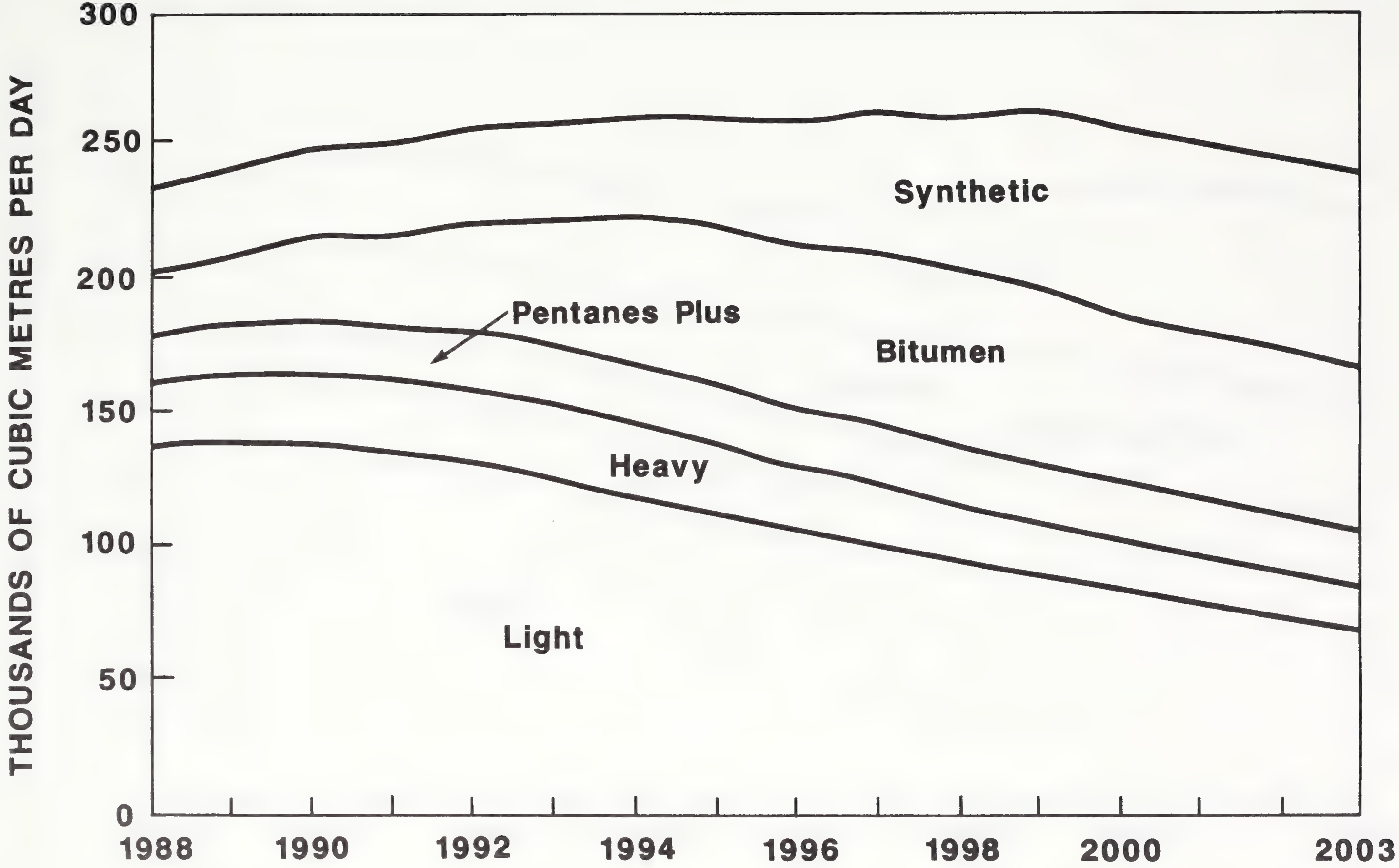

FIGURE 6-1 TOTAL SUPPLY OF ALBERTA'S CRUDE OIL AND EQUIVALENT

BASE CASE 1

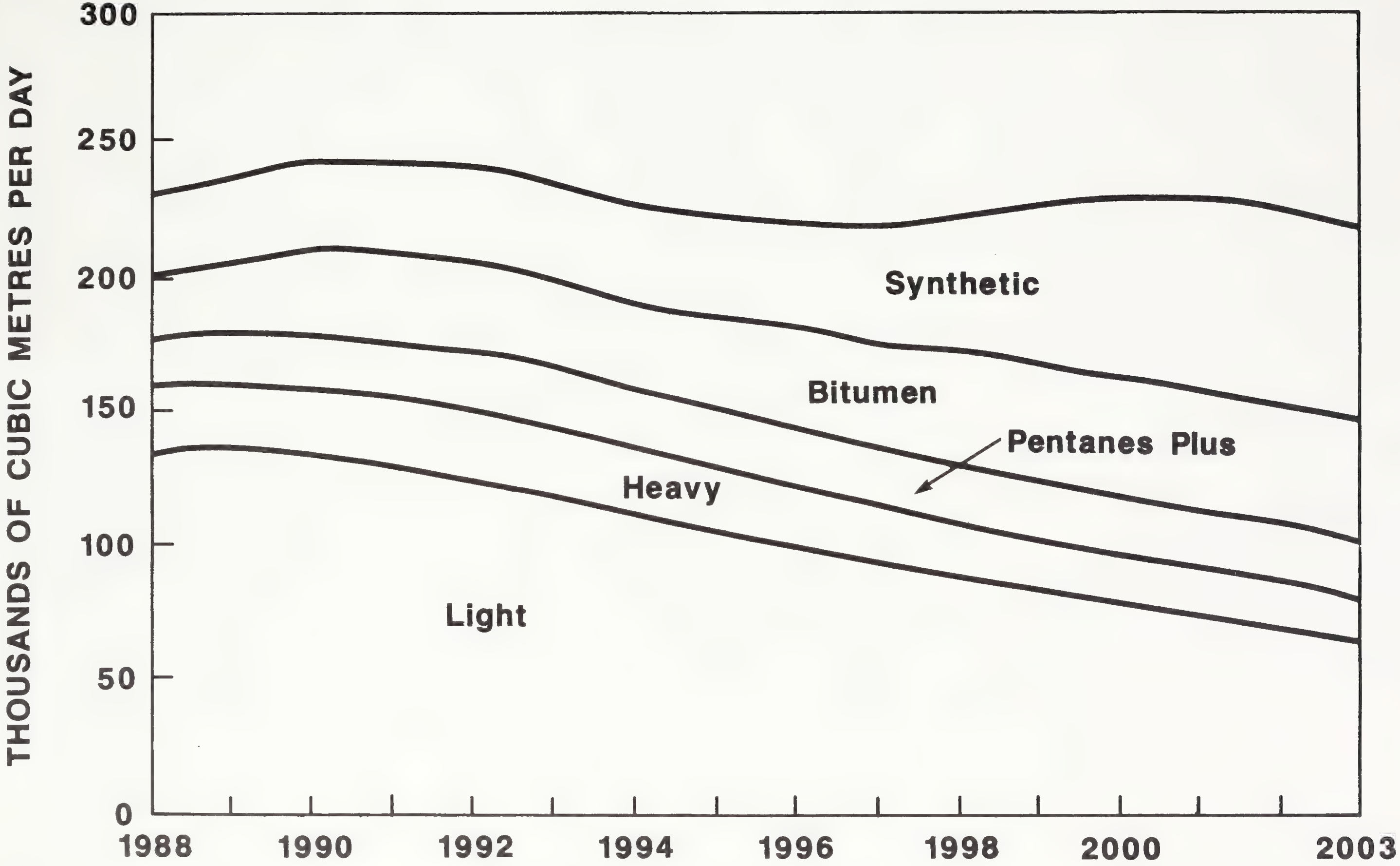

FIGURE 6-2 TOTAL SUPPLY OF ALBERTA'S CRUDE OIL AND EQUIVALENT
BASE CASE 2

7 SENSITIVITY CASES

7.1 LOW PRICE CASE

As discussed in Section 2 of this report, the Board has also prepared a supply forecast to reflect the possible impacts of a more pessimistic outlook for future world oil prices than the Base Cases. The anticipated reduction in total oil supply, relative to Base Cases 1 and 2, has been illustrated in Figure 1 (see Executive Summary).

As a result of reduced cash flow in the industry, drilling activity for conventional crude oil would be expected to drop significantly in the Low Price Case, and would remain at reduced levels for some time. The expected light and heavy crude oil supply from the future discoveries/ additions category is illustrated in Figures 7-1 and 7-2. Although the annual growth in reserves would be lower because of the reduced drilling activity, the total future discoveries/additions reflects the medium geological potential as used in Base Cases 1 and 2. Supply from established pools and tertiary/experimental operations is unlikely to be measurably impacted by lower prices and, therefore, has not been adjusted. Available pentanes plus supply was not considered sensitive to the price forecasts.

The supply forecast for crude bitumen under the Low Price Case is shown in Table 7-1. It is expected that cash flow constraints and the commercial risk for most companies would cause delays in the start-up and expansions of certain projects, despite favourable project economics later on in the forecast. Bitumen supplies are estimated to increase by about 10 per cent over the next 5 years, which would likely be followed by a decline for the rest of the forecast period under the low price scenario. The level of production associated with further postponement of development plans, combined with an expected decline in experimental production, creates a net decline in the Low Price Case. The bitumen upgrader, which was assumed in both base cases, would not likely be built within the forecast time frame under the low price scenario.

The forecast supply of total SCO production in the low price case is also shown in Table 7-1. Maximum production reaches 40 x 10^3 m^3/d by the year 2003. Relative to the base case forecasts, the interval between the construction start-up dates of OSLO and Syncrude's expansion was increased slightly, as it was assumed the common project sponsors would be less likely to finance the construction of both projects simultaneously if they perceived prices to follow the low scenario.

The Board's forecast of total crude oil and equivalent supply by product for the Low Price Case over the 1988 - 2003 forecast period is shown in Table 7-2 and is illustrated in Figure 7-3. Available supply declines significantly over the forecast period. The total production rate of 230 x 10^3 m^3/d in 1991 drops to 153 x 10^3 m^3/d by the year 2003.

7.2 UPPER GEOLOGICAL POTENTIAL - CONVENTIONAL CRUDE OIL

Having regard for recent high drilling activity and resulting reserves addition levels, the Board has identified another sensitivity case to reflect supply if the Upper Geological Potential Case for conventional crude oil materializes (ie, based on the development of reserves with upper geological potential as summarized in Tables 3-1 and 3-2). Price is not a variable in this case. It is anticipated that this forecast would stand a reasonable chance with the price and fiscal regime described for Base Case 1.

The anticipated increase in total conventional crude oil supply, relative to Base Cases 1 and 2 and the Low Price Case, is illustrated in Figure 7-4. The gap between the Upper Geological Potential Case and Base Case 1 widens over the forecast period, and is approximately 19 per cent higher for the Upper Geological Potential Case by the year 2003. The average increase in supply over the forecast period is approximately 8 per cent.

TABLE 7-1 FORECAST OF CRUDE BITUMEN PRODUCTION AND SYNTHETIC CRUDE OIL SUPPLY 1988 - 2003 Low Price Case (thousands of cubic metres per day)

Year	1 Gross Bitumen	2 Synthetic Crude Oil Mining	3 In Situ	4 Total	5 Non-upgraded Bitumen
1988	62	31	-	31	23
1989	62	32	-	32	23
1990	65	33	-	33	25
1991	67	34	-	34	26
1992	69	36	-	36	26
1993	69	36	-	36	25
1994	68	36	-	36	25
1995	68	36	-	36	24
1996	67	36	-	36	24
1997	67	36	-	36	23
1998	66	36	-	36	23
1999	66	36	-	36	22
2000	65	36	-	36	22
2001	66	38	-	38	21
2002	67	39	-	39	21
2003	67	40	-	40	20

TABLE 7-2 FORECAST OF TOTAL CRUDE OIL AND EQUIVALENT SUPPLY
- ALL PRODUCTS
Low Price Case
(thousands of cubic metres per day)

	1	2	3	4	5	6
Year	Light	Heavy	Pentanes Plus	Synthetic	Non-upgraded Bitumen	Total
1988	137	24	18	31	23	233
1989	136	24	19	32	23	234
1990	131	24	20	33	25	233
1991	126	24	20	34	26	230
1992	119	24	22	36	26	227
1993	111	24	22	36	25	218
1994	103	23	22	36	25	209
1995	96	21	22	36	24	199
1996	89	20	22	36	24	191
1997	84	19	22	36	23	184
1998	79	17	22	36	23	177
1999	74	16	22	36	22	170
2000	70	16	22	36	22	166
2001	66	15	22	38	21	162
2002	62	14	22	39	21	158
2003	59	13	21	40	20	153

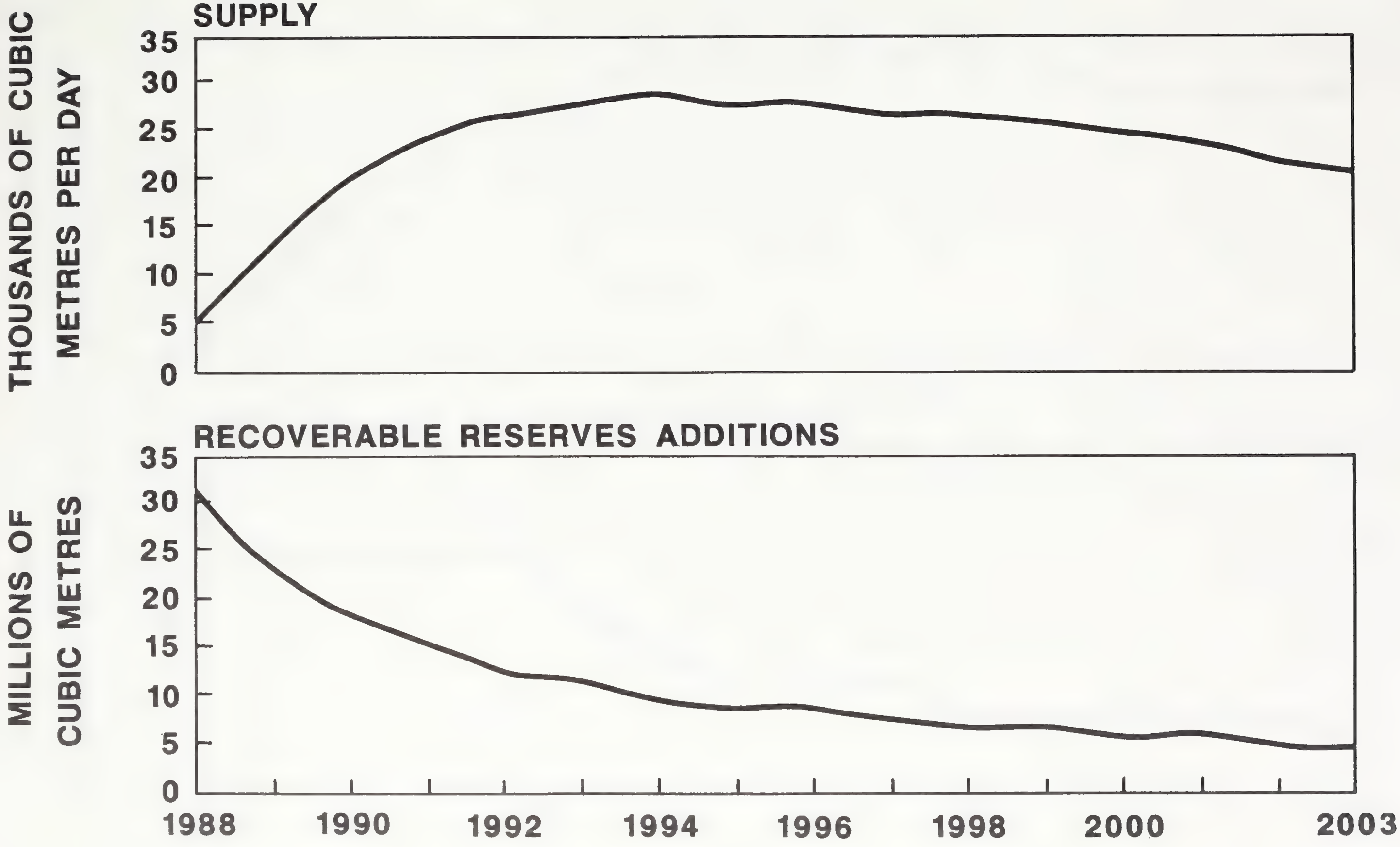

FIGURE 7-1 RESERVES GROWTH AND SUPPLY FROM DISCOVERIES/ADDITIONS
LIGHT CRUDE OIL (LOW PRICE CASE)

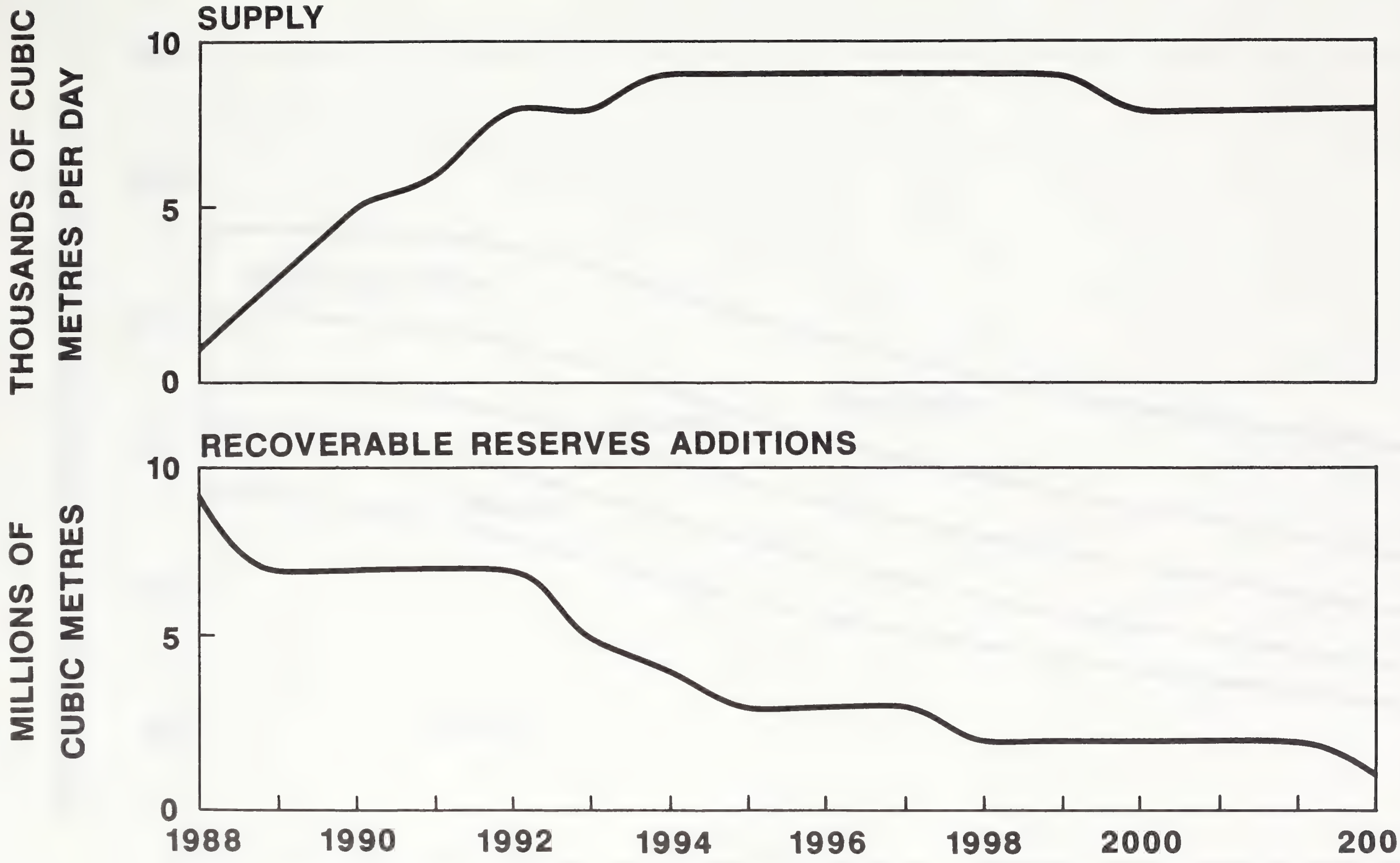

FIGURE 7-2 RESERVES GROWTH AND SUPPLY FROM DISCOVERIES/ADDITIONS
HEAVY CRUDE OIL (LOW PRICE CASE)

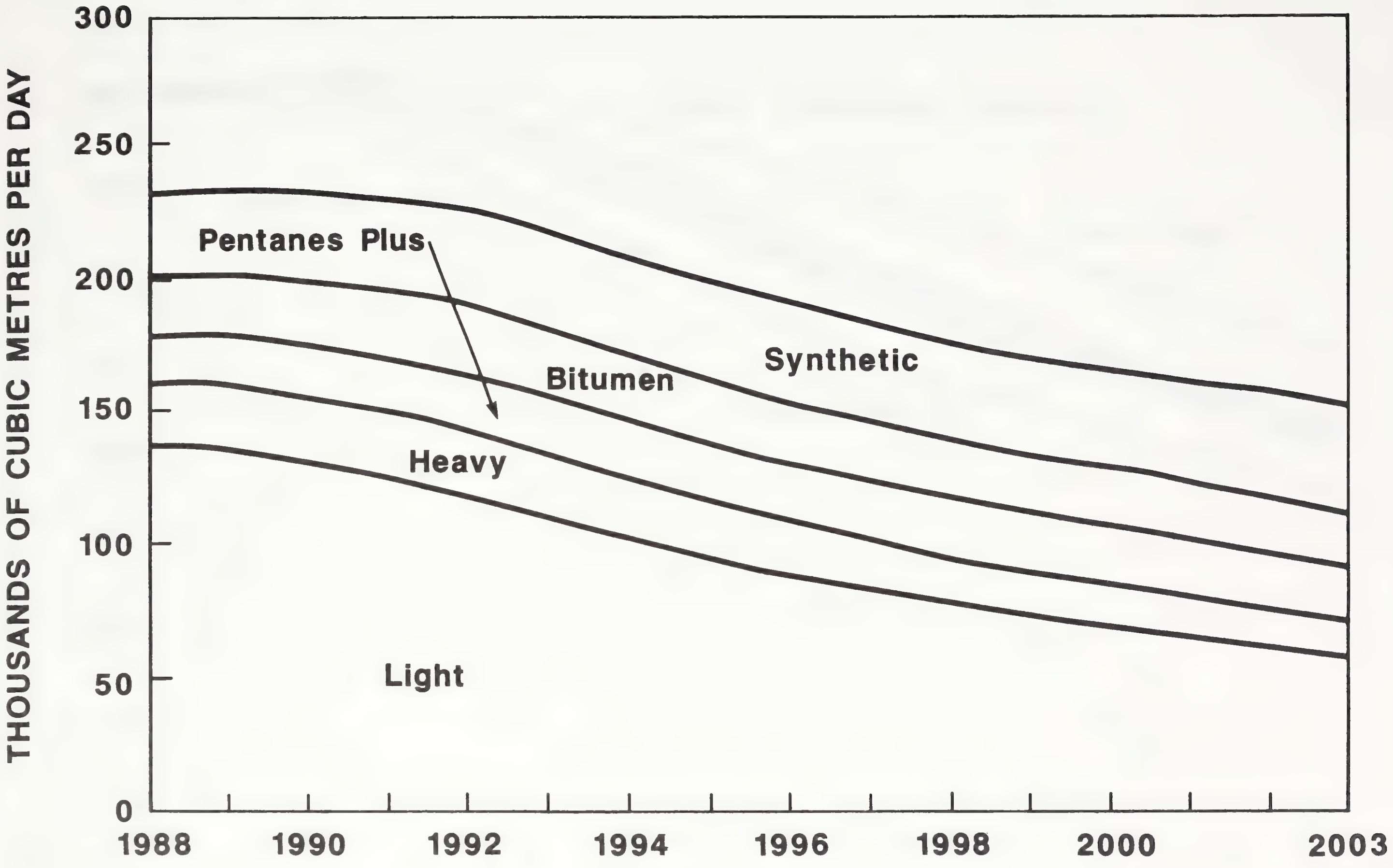

FIGURE 7–3 TOTAL SUPPLY OF ALBERTA'S CRUDE OIL AND EQUIVALENT
LOW PRICE CASE

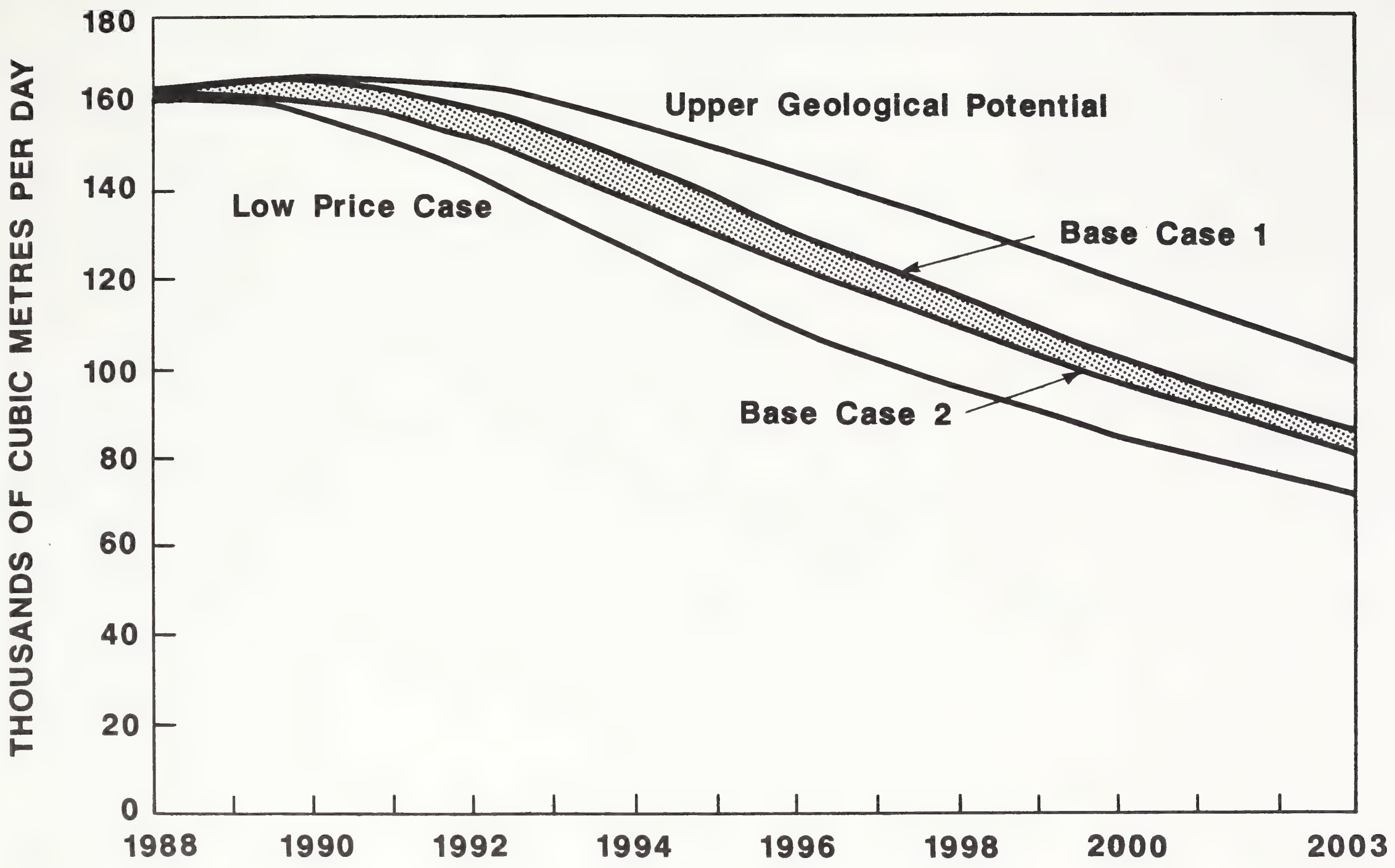

FIGURE 7–4 TOTAL SUPPLY OF CONVENTIONAL CRUDE OIL

APPENDIX A SHORT-TERM FORECAST

APPENDIX A

SHORT-TERM OIL SUPPLY FORECAST
1988-1992

1. Introduction

The Energy Resources Conservation Board (ERCB) has completed a short-term forecast of crude oil and equivalent supply for the period 1988-1992, inclusive. This review is the first part of an assessment of longer term oil productivity in Alberta, which will be completed in the autumn. Table 1 summarizes the results of the forecast under two price scenarios.

The last detailed review of crude oil and equivalent supply was undertaken in 1984, resulting in ERCB Report 85-A "Alberta Oil Supply 1985-2010", although a more recent update was issued in 1987.

2. Conventional Crude Oil

The Board's current assessment of the short-term supply of conventional crude oil shows greater available supply than previously expected. Forecasting methodology has been modified in arriving at this short-term forecast and more recent information has been included in the assessment. Supply forecasts have been generated for both the Light-Medium and Heavy Crude categories of conventional crude oil. The Heavy Crude category is defined to include all crude oil that enters a heavy crude marketing system.

ERCB Report 81-B, issued following a hearing in June 1980, summarizes the reserve based methodology employed by the Board in generating its long-term forecasts. While the Board continues to subscribe to that methodology of long-term forecasting, its evaluation of the period 1983 to 1987 suggests that this long-term methodology may not be appropriate for the short-term, for the following reasons:

- It does not adequately allow for infill drilling that occurs in established Light-Medium and Heavy Crude pools.
- It is not sensitive enough to changes in incentive programs and price fluctuations.
- The normalized productivity profile applied to Light-Medium tertiary reserve growth is inadequate to reflect the field development of EOR schemes. This profile is intended to show the normal incremental production response to the tertiary mechanism. However, it does not account for infill drilling that occurs in the early stages of many tertiary schemes, which accelerates the

base case primary and secondary recoveries before achieving the tertiary response.

Accordingly, the Board decided to modify its approach in assessing the short-term available supply of conventional crude oil to recognize some of these factors. The short-term methodology adopted is predicated on forecasting the behavior of established pools and superimposing the expected behavior of newly drilled wells in both new and established pools. Thus, expectations of drilling activity over the next five years is the primary variable in this assessment.

The historic performance of Light-Medium and Heavy Crude oil wells over the past seven years is shown on Figures 1 and 2, respectively. These figures show the annual average production rate of the pre-1981 wells and the cumulative effect of wells on-production between 1981 and 1987. The monthly production rates during 1987 are also shown on these figures. Declining productivity is observed from wellbores that exist at any given point in time. However, industry activity over this period has maintained a relatively stable supply of Light-Medium Crude and has in fact increased the available supply of Heavy Crude.

2.1 Drilling Activity

With some advice from CPA and IPAC, the ERCB developed two forecasts of conventional well completions over the next five-year period, in light of the historic performance of the drilling industry. These drilling forecasts are shown on Table 1. The base case assumes a continuation of this year's strong activity focused on oil well drilling. This activity level is influenced by several factors including the province's royalty holiday program, and to a lesser extent royalty relief available for some infill wells associated with hydrocarbon miscible flood schemes. As a result, oil well completions should continue at a high level through to the first quarter 1989 at least. Land sales continue to be weighted in favour of potential oil properties. These properties will have to be drilled over the next three to five years to meet with license and lease obligations. While a phasing down of both federal and provincial drilling incentive programs is anticipated, the base case assumes that producer netbacks will be sufficient to maintain relatively high levels of drilling activity over the period. This scenario also recognizes that while the level of natural gas drilling activity will increase over the forecast period, sufficient drilling hardware exists to accommodate the needs of both oil and gas well activity.

The low case reflects a continuation of the current slump in oil prices and expiration of the three-year royalty holiday program after 1 November 1988. Soft oil prices are assumed to linger over much of the next few years, with no real strengthening occurring until the early 1990's. An extension of government drilling incentives are not foreseen in this scenario. The focus over this period will be more on drilling gas wells, with a consequent diversion of some of the available drilling funds away from oil.

3. Light-Medium Crude Oil

The main difficulty experienced by the Board in forecasting available supply of Light-Medium Crude is projecting infill drilling that occurs in older/established pools. This infill drilling results in accelerated production trends along with some recovery improvements. A typical example of this is the Pembina Cardium Pool in which the 350 wells drilled over the past five years, contributed about 1100 m^3/d of incremental production in 1987. Thus, total production from the Pembina Cardium Pool has only declined by about two percent per year over this period. A review of 30 larger pools (older/established pools) shows 1500 infill wells have been drilled over the past five years and that these wells produced about 15 000 m^3/d in 1987. Infill drilling in tertiary schemes has been a contributing factor to this observed productivity. These 1500 wells account for almost 20 percent of the Light-Medium drilling activity over this period. It is difficult to account for some of this activity in the reserve growth/normalized profile approach to forecasting.

3.1 Established Pools

The Board has completed its assessment of the established Light-Medium pools at 31 December 1987. The peak productivity for these pools was found to be 138 $10^3m^3/d$ in December 1987. Individual pool forecasts were based on wellbores that existed at year-end 1987. The largest 190 pools in terms of productivity, representing approximately 80 percent of the total productivity, were forecast on an individual pool basis. An annual average decline rate of about 10.4 percent is forecast over the next five-years. This information was used in the short-term forecast.

3.2 Future Wells

The expected productivity from new drilling was added to the production profile of established pools. The drilling forecast applied over this period includes all types of wells expected to be drilled. In arriving at the expected production from these newly completed wells the following was assumed:

- Seventy two percent of the drilling activity forecast on Table 1 would be in the Light-Medium category.
- Aggregate production from new wells in a given year peaks in December of that year, is held constant for one year and then declines exponentially at 15 percent per year.
- Peak production in the second year averages 8 m^3/d per well for the wells drilled in 1988 and 1989, and 7 m^3/d per well for 1990-1992 wells.

The average production of 8 m^3/d used for wells drilled in 1988 and 1989 assumes the wells will follow the historic average observed over the past five years. It is noted that wells drilled within tertiary schemes have tended to be better than average and have affected the average well productivity by about 1.0 m^3/d/well. The 8 m^3/d used for 1988 and 1989 assumes further drilling candidates exist within both the existing and new tertiary schemes. Further, it is observed that the wells on-production in 1987 averaged 8.9 m^3/d in the first five months of 1988. It should be noted that early productivity in tertiary infill wells is primarily an acceleration of the present depletion mechanism rather than early response to the tertiary mechanism.

4. Heavy Crude Oil

Past forecasting of Heavy Crude oil supply has not adequately accounted for the high activity level and in particular the infill drilling that has occurred in many pools. Drilling density in certain situations has been down to quarter LSD spacing. In many cases new in-place reserves have not been discovered, rather the wells result in improved recovery and/or accelerated production. As shown on Figure 2, new wells drilled in the heavy crude area over the past five years have more than offset the decline of existing wells.

4.1 Established Pools

The Board recently reviewed its long-term forecast of production from established Heavy Crude oil pools at 31 December 1987. The available productivity was found to be 22.3 $10^3m^3/d$ at the end of 1987. Individual pool forecasts were based on the wellbores that existed at year-end 1987. Ninety pools, representing about 80 percent of the total productivity, were forecast on an individual pool basis. The first five years of this forecast of established pools was used in the short-term analysis.

It should be noted that there is about one thousand cubic metres per day of experimental production in conventional Heavy Crude pools, in addition to the 22.3 $10^3 m^3/d$ produced in December 1987.

4.2 Future Wells

The expected productivity from new wells over the next five years was added to the production profile of established pools. The drilling forecast assumed over this period includes all types of drilling (ie; infill wells, stepout development wells and exploration wells). For these new wells the Board assumed:

- Twenty eight percent of the drilling activity forecast on Table 1 would be in the Heavy Crude category.
- Aggregate production from new wells in a given year peaks in December of that year, is held constant for one year and then declines exponentially at 10 percent per year.
- Peak production in the second year averages 4 m^3/d per well for wells drilled between 1988 and 1992.

The average production of 4 m^3/d used for wells drilled between 1988 and 1992 assumes that wells will follow the historic average observed over the past five years.

5. Summary of Conventional Oil Production

Forecast results show only a moderate decline in the available supply of Light-Medium Crude and an increase in the supply of Heavy Crude over the next five years. The Board has a high level of confidence in the forecast of available supply in the initial years of the forecast. However, given the uncertainty about sustaining a high level of drilling in the absence of stable oil prices or incentive programs, the productivity in the later years of the forecast should be used with some degree of caution.

The Board is preparing a projection of the long-term supply of conventional crude oil using the reserve based methodology described in ERCB Report 81-B. Matters such as ultimate potential, normalized profiles and tertiary expectations are currently under review. When the long-term forecast is completed, results will be compared to the short-term analysis with the intent to make adjustments as considered necessary.

6. Bitumen and Synthetic Crude

The current outlook for crude bitumen and synthetic crude oil is lower than that presented in 85-A, primarily due to a re-evaluation of the timing of upgraders for in situ bitumen. ERCB Report 85-A assumed such upgrading to begin in 1991, whereas at this time it is not expected new upgraders will be operational before the mid-1990's.

The current forecast of crude bitumen production was forecast based on existing projects and the ERCB's recognition of projects which are under development, proposed and anticipated. The supply analysis was prepared for each project, and aggregated for use in this forecast. A supply forecast for both the base and low price cases is presented, the difference being the timing of new projects in response to prevailing oil prices.

Synthetic crude oil was forecast on a project specific basis after consultation with the respective operators and takes into account the Syncrude expansion and debottlenecking of Suncor.

7. Pentanes Plus

The pentanes plus supply forecast, although a small proportion of the total, is significantly higher than that presented in 85-A. This increase is due principally to the discovery of the Caroline natural gas field, which upon initial review increased the provincial reserves of pentanes plus by more than 10 percent. As well, revised forecasts of natural gas production have contributed to increased pentanes plus production.

Pentanes plus supply depends directly on the level of natural gas production. As the forecast for natural gas production over the next five years is demand driven, it is not highly sensitive to either oil price case, thus only one supply forecast is presented.

Prepared by ERCB

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August 1988

TABLE 1

FORECAST OF CRUDE OIL AND EQUIVALENT SUPPLY

1988-1992

	Successful Conventional Oil Wells Drilled	$10^3m^3/d$					
		Conventional L-M Oil	Conventional HC Oil	Crude Bitumen	Synthetic Crude Oil	Pentanes Plus	TOTAL
Base Case							
1988	2500	138.0	24.0	23.0	30.5	18.5	234.0
1989	2300	141.0	25.0	26.0	33.0	19.0	244.0
1990	2200	140.0	26.0	31.5	32.5	20.0	250.0
1991	2200	137.0	27.0	35.0	34.5	21.0	254.5
1992	2300	134.0	27.5	40.5	35.0	21.0	258.0
Low Case							
1988	2000	137.0	23.5	23.0	30.5	18.5	232.5
1989	2000	138.0	24.5	26.0	33.0	19.0	240.5
1990	1900	135.0	25.0	31.5	32.5	20.0	244.0
1991	2000	131.0	25.5	35.0	34.5	21.0	247.0
1992	2100	128.0	26.0	39.0	35.0	21.0	249.0

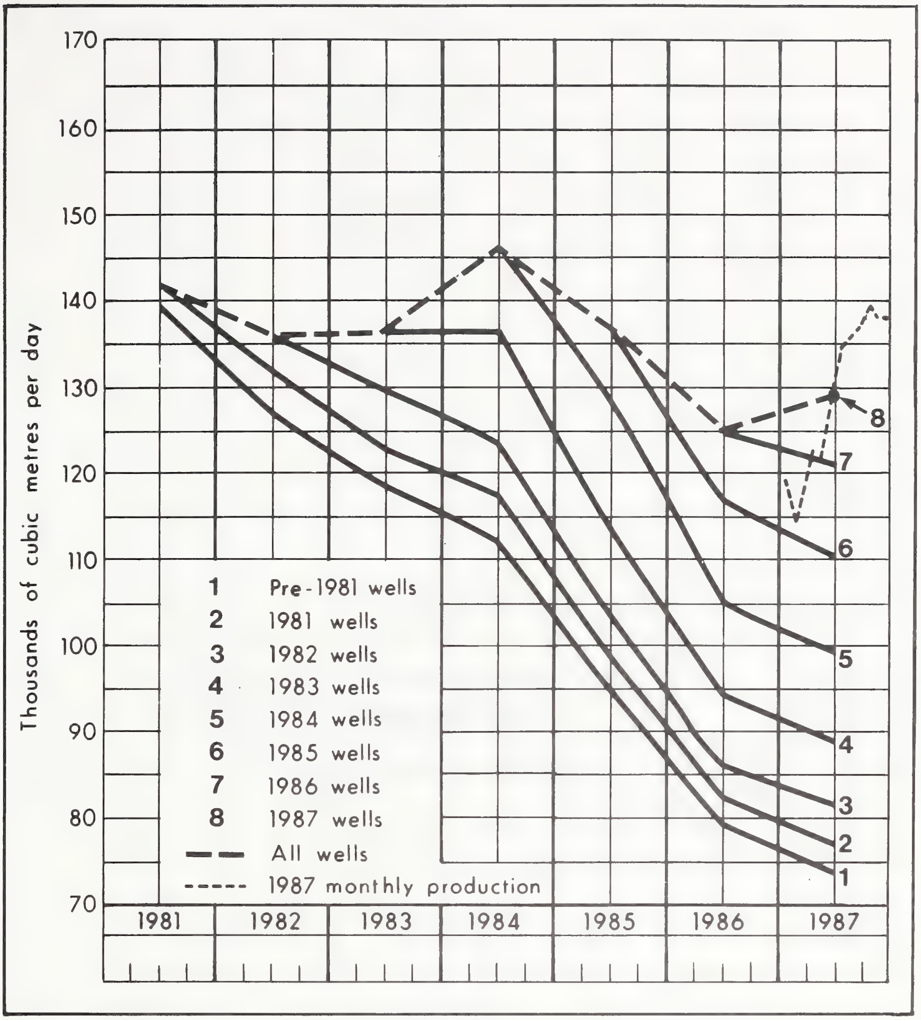

FIGURE 1 LIGHT— MEDIUM CRUDE OIL. Actual Production

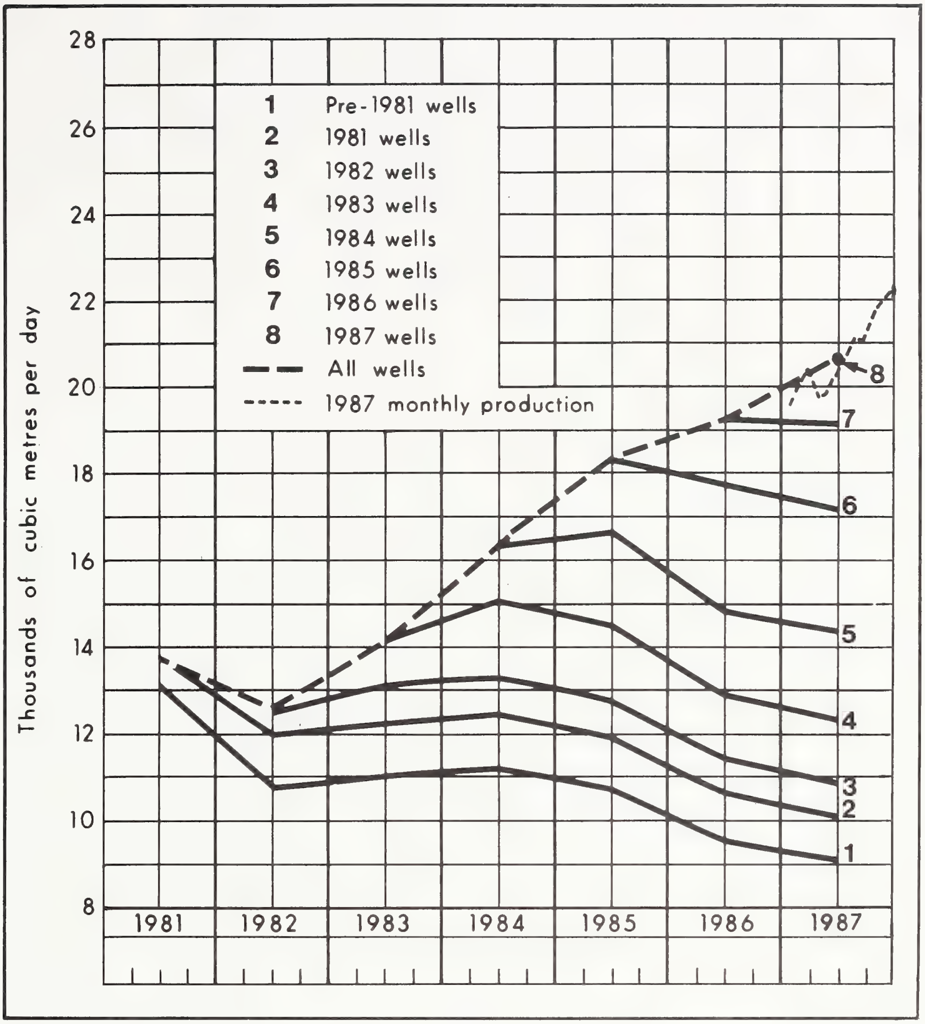

FIGURE 2 HEAVY CRUDE OIL. Actual Production

APPENDIX B OIL SUPPLY FROM ESTABLISHED POOLS IN ALBERTA

PROVINCIAL SUMMARY
FORECAST OF THE SUPPLY OF CONVENTIONAL CRUDE OIL FROM
REMAINING RESERVES AS OF 31 DECEMBER 1987 BY PIPELINE

Pipeline	Table	Productive Capacity - m3/d									
		1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Light & Medium Crude Oil											
A. E. C. - Redwater	1	2235	2033	1843	1669	1511	1370	1241	1124	687	511
Bow River Pipeline	2	3055	2787	2530	2300	2092	1906	1738	1585	1015	784
Cremona Pipeline	3	2066	1893	1709	1538	1368	1217	1084	966	545	391
Federated Pipelines Ltd.	4	17562	16265	14865	13578	12419	11375	10427	9575	6145	4879
Gibson Petroluem Company Ltd.	5	2555	2358	1863	1504	1236	1034	873	745	376	272
Gulf Alberta Pipeline Co. Ltd.	6	8327	7466	6634	5909	5270	4706	4208	3770	2154	1530
Imperial Pipeline - Ellerslie/Leduc	7	3940	3186	2504	1928	1519	1221	1001	838	387	306
Imperial Pipeline - Excelsior	8	217	184	160	138	121	106	93	82	37	28
Murphy Oil Company Ltd. - Milk River	9	1085	949	836	735	648	571	504	445	238	165
Norcen Energy Resources Ltd.	10	850	709	592	494	412	344	287	240	97	57
Peace Pipe Line Ltd.	11	18874	17318	15837	14289	12925	11716	10644	9672	6088	4616
Pembina Pipeline Ltd.	12	26809	25353	23210	20626	18178	15808	13909	12362	7697	6181
Rainbow Pipe Line Ltd.	13	24659	22995	20918	19054	17402	15926	14608	13415	8923	7042
Rangeland Pipe Line Co. Ltd.	14	8595	7724	6824	6049	5374	4784	4272	3819	2255	1603
Texaco Exploration Co.	15	7475	6353	5240	4352	3638	3064	2598	2217	1033	738
Twining Pipeline	16	660	595	558	522	489	458	429	402	292	240
Valley Pipeline	17	400	362	328	297	268	243	220	199	121	-
Tank Car And Truck	18	1850	1812	1785	1746	1651	1561	1478	1399	1063	903
Total Light & Medium		131214	120342	108236	96728	86521	77410	69614	62855	39153	30246

PROVINCIAL SUMMARY
FORECAST OF THE SUPPLY OF CONVENTIONAL CRUDE OIL FROM
REMAINING RESERVES AS OF 31 DECEMBER 1987 BY PIPELINE

Pipeline	Table	Productive Capacity - m3/d									
		1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Heavy Crude Oil											
Bow River Pipeline	19	13785	12512	11243	10100	9077	8164	7341	6612	3933	2874
B P Oil	20	1575	1419	1267	1133	1013	905	809	722	407	292
Federated Pipelines Ltd.	21	22	19	19	18	17	16	15	14	11	10
Husky Oil	22	4100	3759	3401	3079	2787	2530	2292	2081	1285	969
Murphy Oil Company Ltd. - Manito	23	670	598	532	472	421	374	333	296	164	116
Peace Pipe Line Ltd.	24	78	72	68	65	62	59	56	53	41	36
Tank Car And Truck	25	670	612	562	516	474	437	402	372	250	199
Total Heavy		20900	18991	17092	15383	13851	12485	11248	10150	6091	4496

TABLE 1

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL
FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR
A E C - REDWATER (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Redwater D-3	131840	7719	2100	1908	1727	1562	1413	1279	1157	1047	635	470
Others	1103	604	135	125	116	107	98	91	84	77	52	41
Total			2235	2033	1843	1669	1511	1370	1241	1124	687	511

TABLE 2

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR BOW RIVER PIPELINE (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Halkirk Upper Mann. I	2320	2117	550	499	456	417	381	348	318	291	185	142
Halkirk East Ellers. A	514	421	170	146	125	108	93	80	69	59	28	18
Provost Vik Cak & Mann. E	10750	3102	565	509	480	452	425	401	377	355	263	220
Provost Lloydminster O	440	368	150	129	111	95	82	70	61	52	25	16
Youngstown Arcs	784	394	200	169	138	113	92	76	62	51	18	10
Others	10675	5772	1420	1335	1220	1115	1019	931	851	777	496	378
Total			3055	2787	2530	2300	2092	1906	1738	1585	1015	784

TABLE 3

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR CREMONA PIPELINE (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Garrington Cardium A&B 27%	872	111	39	33	29	25	22	20	17	15	8	5
Garrington Viking A 27%	351	204	32	32	30	28	26	25	23	22	16	14
Harmattan E. Viking E	1991	1414	300	300	300	292	264	239	216	196	119	88
Harmattan E. Rundle	12140	1493	380	361	327	296	268	242	219	198	120	89
Harmattan-Elkton Rundle C	11433	1837	740	645	555	477	411	353	304	262	123	79
Lochend Cardium A	904	493	135	125	113	102	92	83	76	68	41	31
Others	6494	1518	440	397	355	318	285	255	229	205	118	85
Total			2066	1893	1709	1538	1368	1217	1084	966	545	391

TABLE 4

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL
FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR
FEDERATED PIPELINES LTD. (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Carson Creek N BHL A&B	26860	5303	1500	1335	1208	1093	989	894	809	732	444	329
Cherhill Banff A	242	141	39	34	31	28	25	23	20	19	11	8
Excelsior D-2	530	22	13	9	8	6	5	4	3	3	-	-
Judy Creek BHL A	58000	12340	2370	2222	2072	1931	1801	1679	1565	1460	1028	834
Judy Creek BHL B	18940	3643	880	831	759	694	634	579	529	484	308	235
Meekwap D-2A	5141	1796	975	808	661	541	442	362	296	242	-	-
Swan Hills BHL C	28960	10110	1350	1350	1316	1252	1191	1133	1078	1025	798	687
Swan Hills BHL A&B	111100	23943	5000	4757	4391	4053	3741	3453	3188	2942	1972	1551
Swan Hills S. BHL A&B	67450	13662	2620	2450	2284	2130	1986	1852	1726	1610	1134	919
Virginia Hills Belloy A	3810	1814	990	814	666	545	445	365	298	244	-	-
Virginia Hills BHL	25200	4647	1500	1365	1210	1073	952	844	748	664	364	254
Others	3627	1104	325	290	259	232	208	187	167	150	86	62
Total			17562	16265	14865	13578	12419	11375	10427	9575	6145	4879

TABLE 5

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL
FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR
GIBSON PETROLEUM COMPANY LTD. (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Bellshill L. Blairmore	14394	5104	2000	1893	1476	1181	967	807	683	586	313	232
Killam Glauconitic S	760	537	270	227	186	152	124	102	83	68	25	14
Killam Glauconitic FF	566	490	165	142	126	112	99	88	78	69	38	26
Others	350	194	120	96	75	59	46	37	29	22	-	-
Total			2555	2358	1863	1504	1236	1034	873	745	376	272

TABLE 6

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR GULF ALBERTA PIPELINE CO. LTD. (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Bashaw D-2B	630	507	117	107	98	91	84	77	71	66	44	35
Chigwell Viking E	815	642	100	90	85	81	77	74	70	67	52	45
Clive D-2A	3510	1137	300	277	250	227	205	185	168	152	92	68
Clive D-3A	6990	1718	505	447	404	366	331	300	271	245	149	110
Drumheller D-2A	1899	449	180	154	133	114	99	85	73	63	30	19
Drumheller D-2B	2880	970	400	343	292	249	212	181	154	131	59	36
Erskine D-3	3830	241	120	103	85	70	58	48	39	32	13	-
Fenn West D-2A	1560	245	125	103	85	70	58	48	40	33	13	-
Fenn West D-3E	666	350	180	150	122	100	82	67	55	45	16	-
Fenn-Big Valley D-2A	51800	4789	1990	1646	1416	1218	1048	902	776	668	315	201
Hussar Glauconitic A	3533	506	200	174	149	128	111	95	82	70	33	21
Joffre D-2	9640	2661	360	347	330	314	299	284	270	257	200	172
Joffre D-3B	825	709	140	140	140	140	140	140	140	140	68	43
Stettler D-3A	3690	435	120	111	100	91	82	74	67	61	37	27
Watts Banff H	851	723	250	220	193	170	149	131	115	101	52	36
Wayne-Rosedale Bas. Q B	872	299	125	105	91	78	67	58	50	43	20	13
West Drumheller D-2A	4660	219	115	92	76	63	52	43	35	29	11	-
Others	42648	11683	3000	2857	2585	2339	2116	1914	1732	1567	950	704
Total			8327	7466	6634	5909	5270	4706	4208	3770	2154	1530

TABLE 7

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR IMPERIAL PIPELINE - ELLERSLIE/LEDUC SYSTEM (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Acheson D-3A	20800	2622	2250	1590	1105	767	533	371	257	179	-	-
Acheson E. Blair. B	687	158	100	82	64	49	39	30	23	18	-	-
Golden Spike D-3A	30000	2064	270	270	258	245	233	222	211	201	156	135
Leduc Woodbend D-3A	39800	848	550	550	449	299	200	133	89	59	-	-
Others	31343	2764	770	694	628	568	514	465	421	381	231	171
Total			3940	3186	2504	1928	1519	1221	1001	838	387	306

TABLE 8

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL
FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR
IMPERIAL PIPELINE - EXCELSIOR (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial $10^3 m^3$	Remaining $10^3 m^3$	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Excelsior D-2 88%	3890	161	92	72	59	47	38	31	25	21	-	-
Others	2672	442	125	112	101	91	83	75	68	61	37	28
Total			217	184	160	138	121	106	93	82	37	28

TABLE 9

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR MURPHY OIL COMPANY LTD. - MILK RIVER (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Manyberries Sunburst Q	600	344	170	136	114	95	79	66	55	46	19	11
Turin Upper Mann. H	600	367	115	102	91	81	73	65	59	53	30	22
Others	5066	2435	800	711	631	559	496	440	390	346	189	132
Total			1085	949	836	735	648	571	504	445	238	165

TABLE 10

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR NORCEN ENERGY RESOURCES LTD. (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Joarcam Viking	17700	1776	850	709	592	494	412	344	287	240	97	57
Total			850	709	592	494	412	344	287	240	97	57

TABLE 11

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR PEACE PIPE LINE LTD. (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Ante Creek BHL	3560	1642	179	178	171	165	158	152	146	140	115	102
Cherhill Banff A 78%	858	501	136	124	112	101	91	83	75	68	41	31
Fox Creek BHL A	576	293	165	135	108	86	69	56	45	36	12	-
Gift Slave Point A	1789	1490	200	199	189	180	171	163	155	147	114	99
Goose River BHL A	8832	2871	630	604	558	515	475	439	405	374	250	197
Kakwa A Cardium A	1499	945	460	397	331	276	231	193	161	134	54	-
Kaybob BHL A	17600	1816	785	667	568	484	412	351	299	255	114	70
Kaybob S. Triassic A	17800	5669	1290	1190	1099	1014	936	864	798	736	493	388
Loon Granite Wash E	466	422	100	90	83	77	71	65	60	56	37	29
Nipisi Gilwood A 40%	22948	6783	1850	1631	1475	1335	1208	1093	989	894	542	402
Nipisi Keg River SS E 40%	287	145	42	37	33	30	27	25	22	20	12	9
Panny Keg River D	1040	859	150	137	129	121	114	108	101	96	71	59
Pouce Coupe S. Bound. B	1200	921	160	146	138	130	122	115	108	102	76	63
Progress Halfway B	631	484	100	92	86	80	74	69	65	60	43	34
Red Earth Slave Point A	936	360	110	100	90	80	72	64	58	52	30	21
Red Earth Grnaite Wash A	4320	1441	275	257	240	223	208	194	181	169	119	96
Rycroft Charlie Lake A	968	754	210	185	167	151	137	124	112	101	61	46
Rycroft Halfway C	660	517	145	130	117	106	96	87	79	71	43	32
Simonette D-3	6100	367	200	162	131	106	86	69	56	46	16	-

TABLE 11 Continued

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL
FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR
PEACE PIPE LINE LTD. (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial $10^3 m^3$	Remaining $10^3 m^3$	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Snipe Lake BHL	12410	4054	590	561	533	507	483	459	437	415	323	278
Spirit River Halfway F	2297	1859	620	552	490	434	385	342	303	269	147	103
Sturgeon Lake D-3	3530	212	125	99	79	64	51	41	33	26	-	-
Sturgeon Lake South D-3	27800	7057	2500	2500	2338	1972	1663	1402	1183	997	425	255
Sturgeon Lake South D-3C	450	296	100	89	79	70	62	55	49	43	24	17
Utikuma Lake KR SS A 31%	2372	680	341	292	241	199	165	136	112	93	36	-
Utikuma Lake KR SS M 31%	118	71	29	25	21	18	16	13	12	10	5	-
Utikuma Lake KR SS N 31%	465	215	102	87	72	59	49	40	33	28	11	6
Valhalla Doe Creek I	5903	5043	550	550	550	550	550	550	550	534	416	358
Valhalla Halfway C	460	330	180	145	118	95	77	63	51	41	14	-
Wapiti Cardium A&B	1365	1255	115	107	104	101	98	95	92	90	77	70
Wembly Halfway B	4600	3442	910	858	777	702	636	575	520	471	285	211
Windfall D-3A	2950	724	125	117	110	104	98	92	87	82	61	51
Others	37272	24194	5400	4875	4500	4154	3834	3539	3267	3016	2021	1589
Total			18874	17318	15837	14289	12925	11716	10644	9672	6088	4616

TABLE 12

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR PEMBINA PIPELINE LTD. (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Bigoray Cardium B	1066	625	275	233	197	166	140	118	100	84	36	22
Bigoray Nisku B	900	426	130	130	130	130	130	123	96	74	21	10
Bigoray Nisku C	552	472	120	120	120	120	120	120	120	109	31	15
Bigoray Nisku D	1100	762	150	150	150	150	150	150	150	150	78	43
Bigoray Nisku E	900	518	120	120	120	120	120	120	120	113	41	23
Bigoary Nisku F	2130	1064	450	450	450	417	308	227	168	124	28	11
Bigoray Nisku G	408	137	100	80	59	43	32	24	18	13	-	-
Bigoray Nisku H	924	562	200	200	200	200	200	149	110	82	18	-
Bigoray Nisku K	383	173	110	103	76	56	41	31	23	17	-	-
Brazeau River Nisku A	4188	1384	980	742	549	405	300	222	164	121	27	11
Brazeau River Nisku B	1470	660	400	376	277	205	151	112	83	61	13	-
Brazeau River Nisku D	1760	846	330	330	330	330	268	198	146	108	24	10
Brazeau River Nisku E	1568	523	375	284	210	155	114	85	63	46	10	-
Brazeau River Nisku I	369	192	100	100	93	68	51	37	28	20	-	-
Carrot Creek Cardium F	1901	1494	420	392	351	314	282	252	226	202	117	84
Crystal Viking A	5493	4034	775	742	692	645	602	561	523	488	344	279
Cyn-Pem Cardium D	2170	1740	540	487	436	391	350	314	281	252	145	104
Cyn-Pem Cardium L	350	241	100	87	74	64	55	47	41	35	17	11
Highvale Cardium C	387	249	100	85	73	64	56	48	42	36	18	12

TABLE 12 Continued

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL
FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR
PEMBINA PIPELINE LTD. (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Niton Rock Creek F	2021	971	130	130	126	119	114	108	103	98	76	66
Pembina Key Belly Riv B	9680	3476	400	366	352	338	325	312	300	288	236	209
Pembina Key Belly Riv C	3080	912	265	242	216	194	174	156	139	125	72	52
Pembina Key Belly Riv M	1946	825	225	202	183	166	150	135	123	111	67	50
Pembina Key Belly Riv U	2130	979	160	156	147	138	130	123	116	109	81	67
Pembina Belly R FFF & GGG	730	501	130	115	106	96	88	81	74	67	43	33
Pembina Belly River DDD	898	712	200	176	159	144	130	118	107	96	58	43
Pembina Cardium	239000	73810	6500	6162	5872	5602	5350	5115	4895	4689	3830	3424
Pembina Ostracod E	1197	785	340	292	246	208	175	148	124	105	45	27
Pembina Nisku A	1960	956	550	548	405	299	221	164	121	89	20	-
Pembina Nisku C	773	242	180	134	99	74	54	40	30	22	-	-
Pembina Nisku D	3460	1698	600	600	600	600	595	440	325	241	53	21
Pembina Nisku G	2100	980	600	553	408	301	223	164	122	90	20	-
Pembina Nisku K	2080	1157	580	580	534	393	291	215	159	117	26	11
Pembina Nisku L	4100	2521	1150	1150	1150	910	672	497	367	272	60	24
Pembina Nisku M	2140	1218	600	600	566	418	309	228	169	125	28	11
Pembina Nisku N	720	559	200	200	200	200	199	147	109	80	18	-
Pembina Nisku O	1240	796	350	350	350	303	224	165	122	90	20	-
Pembina Nisku P	3315	2104	930	930	930	784	579	428	316	234	52	21

TABLE 12 Continued

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL
FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR
PEMBINA PIPELINE LTD. (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Pembina Nisku Q	2350	1817	660	660	660	660	619	456	337	250	55	22
Pembina Nisku S	350	186	100	100	89	66	49	36	27	20	-	-
Pembina Field Others	10673	6543	1050	1050	1018	959	903	851	801	754	559	467
WestPem Nisku A	1990	920	580	514	380	281	208	154	113	84	19	-
WestPem Nisku C	3200	1689	900	900	745	551	407	301	222	164	36	15
WestPem Nisku D	1540	655	430	364	269	198	147	108	80	59	13	-
Willesden Grn Cardium A 75%	19298	6658	780	758	728	699	672	646	620	596	488	433
Willesden Grn Viking A 75%	585	203	94	78	66	55	47	39	33	28	12	-
Others	16381	9049	2350	2232	2019	1827	1653	1495	1353	1224	742	550
Total			26809	25353	23210	20626	18178	15808	13909	12362	7697	6181

TABLE 13

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL
FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR
RAINBOW PIPE LINE LTD. (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial $10^3 m^3$	Remaining $10^3 m^3$	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Evi KR A & GR Wash N	978	799	280	275	237	204	175	151	130	111	53	33
Evi KR B & GR Wash P	1327	1167	315	284	257	232	210	190	172	156	94	70
Golden Slave Point A	3700	1716	235	227	216	205	195	186	177	168	131	113
Mitsue Gilwood A	60850	17747	4500	4297	3888	3518	3183	2879	2605	2357	1429	1058
Nipisi Gilwood A 60%	34422	10174	2770	2448	2215	2004	1813	1640	1484	1343	814	603
Nipisi Keg River SS E 60%	431	218	63	56	50	46	41	37	34	30	18	14
Otter Granite Wash A	736	517	160	140	125	112	101	90	81	72	42	30
Otter Granite Wash F	776	705	200	174	157	142	129	117	105	95	58	43
Rainbow Muskeg C	600	247	155	120	94	74	58	45	36	28	-	-
Rainbow Muskeg O	816	623	110	102	96	91	85	80	76	71	53	44
Rainbow Keg River A	12600	3678	670	645	601	560	522	487	454	423	298	242
Rainbow Keg River B	30800	11493	1450	1450	1404	1335	1270	1208	1149	1093	851	733
Rainbow Keg River E	2174	454	320	242	181	135	101	75	56	42	10	-
Rainbow Keg River F	19100	3520	935	838	758	686	621	561	508	460	279	206
Rainbow Keg River G	1840	507	130	117	107	98	90	82	75	68	44	33
Rainbow Keg River H	1760	396	135	116	103	92	81	72	64	57	31	22
Rainbow Keg River I	3570	1022	100	100	100	100	100	100	96	92	75	67
Rainbow Keg River K	623	148	95	74	58	46	36	28	22	18	-	-
Rainbow Keg River N	1000	258	175	135	103	78	60	45	35	26	-	-

TABLE 13 Continued

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL
FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR
RAINBOW PIPE LINE LTD. (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial $10^3 m^3$	Remaining $10^3 m^3$	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Rainbow Keg River O	4960	1183	138	130	125	120	115	111	107	102	84	74
Rainbow Keg River Z	1090	338	245	185	137	101	75	55	41	30	-	-
Rainbow Keg River AA	9046	2416	310	310	302	287	273	260	247	235	183	157
Rainbow Keg River FF	1825	619	445	334	247	182	135	100	73	54	12	-
Rainbow Keg River GG	893	397	170	144	123	105	89	76	65	55	25	15
Rainbow Keg River OO	447	179	130	97	73	55	42	31	24	18	-	-
Rainbow Keg River RRR	690	434	185	157	134	114	97	83	71	60	27	17
Rainbow Keg River O2O	455	439	310	234	174	130	97	73	54	41	-	-
Rainbow Field Others	21552	9285	1760	1698	1583	1476	1376	1283	1196	1115	786	637
Rainbow S. Keg River B	5210	1771	350	350	328	303	280	258	238	220	148	116
Rainbow S. Keg River C	1130	677	145	140	129	119	110	102	94	87	58	46
Rainbow S. Keg River E	2997	730	100	100	97	92	87	83	79	75	59	50
Seal Slave Point A	560	236	125	103	84	69	56	46	38	31	11	-
Seal Slave Point D	484	438	110	103	94	86	79	72	66	60	38	29
Slave Slave Point H	1520	1088	300	264	239	216	196	177	160	145	88	65
Slave Slave Point S	1175	817	210	183	167	153	140	127	117	106	68	52
Trout Keg River A	588	495	125	115	105	96	88	80	73	67	42	32
Utikuma Lake KR SS A 69%	5278	1514	759	650	537	444	367	303	251	207	80	-
Utikuma Lake KR SS M 69%	262	157	66	55	48	41	35	30	26	23	11	7

TABLE 13 Continued

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL
FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR
RAINBOW PIPE LINE LTD. (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Utikuma Lake KR SS N 69%	1035	479	228	193	159	132	109	90	74	61	24	13
Others	59465	36003	5650	5610	5283	4975	4685	4413	4155	3913	2899	2421
Total			24659	22995	20918	19054	17402	15926	14608	13415	8923	7042

TABLE 14

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR RANGELAND PIPE LINE CO. LTD. (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Caroline Cardium E	2213	977	450	376	314	262	219	183	153	127	52	30
Caroline Rundle A	2460	503	250	204	168	139	115	95	78	65	25	14
Ferrier Cardium D	3142	1343	270	240	223	208	194	181	169	158	111	90
Ferrier Cardium E	4920	2324	415	412	384	358	334	311	290	270	190	154
Ferrier Cardium G & L	3658	2398	550	510	471	435	401	370	342	316	212	166
Garrington Cardium A & B 73%	2358	300	106	93	81	71	63	55	48	42	22	15
Garrington Viking A 73%	949	550	88	88	83	78	74	69	65	62	46	38
Gilby Jurrasic B	3680	1066	200	193	180	168	156	146	136	127	89	72
Innisfail D-3	13267	1561	820	674	551	451	369	302	247	202	74	-
Medicine River Viking D	915	500	240	205	169	140	115	95	79	65	25	14
Medicine River Glauc A	2275	559	260	219	182	152	127	106	89	74	30	17
Medicine River Jurass C	3007	1448	280	258	240	224	209	195	182	169	119	97
Medicine River Jurass D	2174	475	110	100	92	85	79	73	67	62	42	33
Medicine River Pekisko I	1330	420	120	107	97	88	79	72	65	59	36	26
Ricinus Cardium A	1991	543	275	229	188	153	126	103	84	69	25	14
Sundre Rundle A	5788	760	340	282	238	200	169	142	120	101	43	26
Sylvan Lake Elk-Shunda D	832	271	110	97	83	72	62	53	46	39	19	12
Sylvan Lake Pekisko B	2300	632	245	212	183	157	135	116	100	86	41	26
Sylvan Lake Pekisko C	963	434	165	143	124	108	94	82	71	62	31	20

TABLE 14 Continued

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL
FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR
RANGELAND PIPE LINE CO. LTD. (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Willesden Grn Cardium A 25%	6432	2220	260	252	242	233	224	215	207	198	162	144
Willesden Grn Viking A 25%	195	68	31	25	21	18	15	12	11	9	4	-
Wimborne D-3A	3750	925	460	388	323	270	225	188	157	131	53	-
Others	27029	9834	2550	2417	2187	1979	1790	1620	1466	1326	804	595
Total			8595	7724	6824	6049	5374	4784	4272	3819	2255	1603

TABLE 15

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL
FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR
TEXACO EXPLORATION CO. (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial $10^3 m^3$	Remaining $10^3 m^3$	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Bonnie Glen D-3A	84700	6071	3000	2571	2103	1721	1407	1151	942	770	282	154
Westerose D-3	23100	3154	2200	1767	1306	965	713	527	390	288	-	-
Wizard Lake D-3A	59000	8504	1940	1738	1605	1481	1367	1262	1165	1076	721	567
Others	4046	661	335	277	226	185	151	124	101	83	30	17
Total			7475	6353	5240	4352	3638	3064	2598	2217	1033	738

TABLE 16

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR TWINING PIPELINE (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Twining Rundle A & LMA	7240	2939	540	485	457	430	405	381	359	338	251	209
Others	859	473	120	110	101	92	84	77	70	64	41	31
Total			660	595	558	522	489	458	429	402	292	240

TABLE 17

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL
FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR
VALLEY PIPELINE (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Turner Valley Rundle	23175	1172	400	362	328	297	268	243	220	199	121	-
Total			400	362	328	297	268	243	220	199	121	-

TABLE 18

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR TANK CAR AND TRUCK (LIGHT-AND-MEDIUM CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Boundary Lake S. Trias. E	4070	1414	350	312	285	260	238	217	199	182	116	88
Others	15683	12036	1500	1500	1500	1486	1413	1344	1279	1217	947	815
Total			1850	1812	1785	1746	1651	1561	1478	1399	1063	903

TABLE 19

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL
FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR
BOW RIVER PIPELINE (HEAVY CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Alderson Upper Mann Z	492	335	95	87	79	72	65	59	53	48	29	22
Alderson Field Other	3174	1544	410	372	337	305	276	250	226	204	124	92
Badger Upper Mann B	699	610	80	80	80	79	75	71	68	64	50	43
Bantry Mannville A	8478	2659	750	669	605	547	495	448	405	367	222	165
Bantry Mannville D	1426	567	155	142	128	116	105	95	86	78	47	35
Bantry Pekisko G	230	169	50	48	43	39	35	32	29	26	16	12
Bow Island Glauc A	523	424	95	91	84	78	72	66	61	56	38	30
Cessford Basal Color A	2212	449	65	65	62	59	56	53	51	48	38	32
Cessford Mannville C	3259	1044	280	255	231	209	189	171	154	140	85	63
Cessford Mannville Y & Z	804	405	85	78	73	68	63	59	55	51	36	29
Chin Coulee Bas Mann A	1054	234	70	63	57	51	47	42	38	35	21	15
Countess Upper Mann B	1488	291	100	87	77	69	61	54	48	42	23	16
Countess Upper Mann D	6442	1316	540	474	408	351	302	259	223	192	91	58
Countess Upper Mann H	2444	454	150	133	118	104	92	82	73	64	35	25
Countess Upper Mann O	1200	479	105	101	94	86	80	74	68	63	42	33
Enchant Ellis C	322	288	95	88	78	69	61	54	48	43	23	16
Enchant Ellis D	478	330	110	98	87	77	68	61	54	48	26	18
Grand Forks Upper Mann B	1240	282	95	86	76	67	60	53	47	42	23	16
Grand Forks Lower Mann D	6230	1412	540	481	418	364	316	275	239	207	103	67

TABLE 19 Continued

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL
FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR
BOW RIVER PIPELINE (HEAVY CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial $10^3 m^3$	Remaining $10^3 m^3$	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Grand Forks Lower Mann K&V	2250	625	170	155	141	127	115	104	94	85	52	38
Grand Forks Sawtooth A	289	208	70	65	58	51	46	41	36	32	17	12
Grand Forks Sawtooth D	348	248	85	76	67	60	53	47	42	37	20	14
Grand Forks Sawtooth L	652	449	145	131	116	103	91	81	72	64	35	24
Grand Forks Sawtooth N	767	622	200	179	159	141	125	110	98	87	48	33
Grand Forks Sawtooth O	1846	1320	415	371	329	292	259	230	204	181	99	69
Grand Forks Sawtooth S	431	135	50	45	40	35	31	28	25	22	12	-
Grand Forks Sawtooth T	933	554	180	160	142	126	112	99	88	78	43	30
Grand Forks Sawtooth MM	2314	1020	325	288	255	226	201	178	158	140	77	54
Grand Forks Sawtooth NN	414	203	70	64	56	50	44	39	35	31	17	12
Grand Forks Sawtooth OO	1058	377	125	111	99	88	78	69	61	54	30	21
Grand Forks Sawtooth SS	544	341	110	102	90	80	71	63	56	50	27	19
Grand Forks Sawtooth VV	195	150	55	49	44	39	34	30	27	24	13	-
Grand Forks Sawtooth WW	2221	1464	500	444	394	349	310	274	243	216	118	83
Grand Forks Field Other	2034	1361	360	329	298	269	244	221	199	181	109	81
Hays Lower Mannville A	1792	331	95	86	77	70	63	57	52	47	28	21
Hays Lower Mannville O	322	314	90	82	74	67	61	55	50	45	27	20
Hays Sawtooth B	284	177	55	49	45	40	37	33	30	27	16	12
Hays Sawtooth C	649	404	130	120	106	94	83	74	66	58	32	22

TABLE 19 Continued

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL
FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR
BOW RIVER PIPELINE (HEAVY CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Horsefly Lake Mannville	1338	322	90	84	76	69	62	56	51	46	28	21
Jenner Upper Mann E	981	202	60	56	50	46	41	37	34	31	19	14
Jenner Upper Mann O	678	525	170	152	135	120	106	94	83	74	41	28
Johnson Glauconitic B	465	373	125	110	98	87	77	68	61	54	29	21
Lathom Upper Mann A	2346	526	170	152	135	120	106	94	83	74	41	28
Little Bow Upper Mann I	340	199	60	55	50	45	41	37	33	30	18	13
Little Bow Upper Mann U	501	368	105	95	86	77	70	63	57	52	32	23
Little Bow Upper Mann W	450	324	75	71	65	60	56	51	47	44	29	23
Little Bow Field Other	1361	828	200	187	171	156	143	131	119	109	69	53
Medicine Hat Glauc C	1047	898	285	255	226	201	178	158	140	124	68	47
Provost Upper Mann B	831	409	60	60	58	55	52	50	47	45	35	30
Provost Upper Mann BB	847	583	190	168	149	132	117	104	92	82	45	31
Provost Lower Mann Z	327	256	75	68	62	56	51	46	41	38	23	17
Provost Dina A	1376	1211	380	341	303	268	238	211	187	166	91	63
Provost Dina C	423	300	90	78	71	64	58	52	47	43	26	19
Provost Dina L	191	184	65	58	52	46	40	36	32	28	15	11
Provost Dina N	997	795	255	227	201	178	158	140	124	110	60	42
Provost Dina O	186	136	50	45	40	35	31	28	25	22	12	-
Provost Dina S	1382	1253	395	353	313	277	246	218	193	172	94	66

TABLE 19 Continued

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL
FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR
BOW RIVER PIPELINE (HEAVY CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial $10^3 m^3$	Remaining $10^3 m^3$	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Provost Basal Quartz C	1065	856	270	244	216	192	170	151	134	118	65	45
Provost Field Other	11694	3702	390	390	376	361	347	333	320	307	252	223
Ronalane Sawtooth B	290	244	80	75	67	59	52	47	41	37	20	14
Suffield Upper Mann J	1585	1053	335	298	264	234	207	184	163	145	79	55
Taber Mannville D	2440	560	140	128	117	107	98	90	82	75	48	36
Taber North Glauc A	2800	1928	490	460	420	384	351	321	293	268	171	130
Taber North Glauc C	519	335	95	87	79	72	65	59	53	48	29	22
Taber North Glauc E	388	275	70	67	62	56	51	47	43	39	25	19
Taber North Taber K	381	264	90	80	71	63	56	50	44	39	21	15
Taber South Mannville A	1379	401	105	95	86	79	72	66	60	55	35	27
Taber South Mannville B	2298	364	100	94	85	77	69	63	57	51	31	23
Turin Upper Mannville C	484	247	70	67	60	55	49	45	40	37	22	16
Others	12591	5599	1550	1408	1274	1152	1043	943	853	772	468	347
Total			13785	12512	11243	10100	9077	8164	7341	6612	3933	2874

TABLE 20

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR B P OIL (HEAVY CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Chauvin Mannville A	1398	273	80	72	65	59	53	48	44	39	24	18
Chauvin South Sparky E	1349	724	190	179	162	147	133	120	109	98	59	44
Chauvin South Sparky H	841	281	100	90	79	70	61	54	47	41	21	14
Chauvin South Spky A & B	1788	511	165	149	132	117	104	92	81	72	40	28
Chauvin South Lloyd C	322	101	50	40	34	29	25	22	19	16	-	-
David Lloydminster C	970	678	215	195	173	153	136	121	107	95	52	36
Hayter Dina A 38%	878	610	205	183	163	144	128	113	100	89	49	34
Hayter Dina B 38%	433	271	87	77	68	60	54	47	42	37	21	14
Hayter Dina I 38%	206	192	63	54	48	43	38	34	30	27	15	10
Others	3134	1573	420	380	343	311	281	254	230	208	126	94
Total			1575	1419	1267	1133	1013	905	809	722	407	292

TABLE 21

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR FEDERATED PIPELINES LTD. (HEAVY CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Cherhill Banff F 22%	185	148	22	19	19	18	17	16	15	14	11	10
Total			22	19	19	18	17	16	15	14	11	10

TABLE 22

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR HUSKY OIL (HEAVY CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial $10^3 m^3$	Remaining $10^3 m^3$	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Lloydminster Sparky B	698	248	60	56	52	48	44	41	37	35	23	18
Lloydminster Sparky G	1101	481	135	122	110	100	90	82	74	67	40	30
Lloydminster Sparky K	1265	609	165	152	137	124	112	102	92	83	50	37
Lloydminster Spky C & GP A	1568	357	100	92	83	75	68	62	56	50	31	23
Lloydminster Spaky & GP C&D	4120	1302	190	173	165	157	149	142	135	129	100	86
Lloydminster Field Other	2665	1032	280	251	227	205	186	168	152	138	83	62
Morgan Sparky A	568	360	100	93	84	76	69	62	56	51	31	23
Morgan Lloydminster A	873	527	145	133	120	109	98	89	80	73	44	33
Viking Kinsella Wainw B	5793	1868	530	484	438	396	358	324	293	265	161	119
Wainwright Wainwright B	420	328	50	50	48	45	43	41	39	37	29	25
Wainwright Wainw & Spky A	14490	4519	1230	1156	1046	947	856	775	701	634	385	285
Wainwright Nisku A	262	125	95	72	54	40	29	22	16	12	-	-
Wildmere Lloyd A & Spky E	3375	1619	430	391	353	320	289	262	237	214	130	96
Others	3638	2085	590	534	484	437	396	358	324	293	178	132
Total			4100	3759	3401	3079	2787	2530	2292	2081	1285	969

TABLE 23

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR MURPHY OIL COMPANY LTD. - MANITO (HEAVY CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Hayter Dina A 62%	1432	995	335	300	266	235	209	185	164	146	80	56
Hayter Dina B 62%	706	443	143	125	111	99	88	78	69	61	33	23
Hayter Dina I 62%	336	314	102	91	81	71	63	56	50	44	24	17
Others	802	315	90	82	74	67	61	55	50	45	27	20
Total			670	598	532	472	421	374	333	296	164	116

TABLE 24

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR PEACE PIPE LINE LTD. (HEAVY CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Cherhill Banff F 78%	657	524	78	72	68	65	62	59	56	53	41	36
Total			78	72	68	65	62	59	56	53	41	36

TABLE 25

SUMMARY OF FORECAST PRODUCTIVE CAPACITY OF CONVENTIONAL CRUDE OIL FROM REMAINING RESERVES AS OF 31 DECEMBER 1987 FOR TANK CAR & TRUCK (HEAVY CRUDE OIL)

Pool	Reserves Used In Forecast		Productive Capacity - m^3/d									
	Initial 10^3m^3	Remaining 10^3m^3	1988	1989	1990	1991	1992	1993	1994	1995	2000	2003
Alexis Banff A	1140	734	110	101	96	92	87	83	79	75	58	50
Sibbald Upper Mann C	1296	890	285	252	224	198	176	156	138	123	67	47
St. Anne Banff C	263	181	55	50	46	41	37	34	30	28	17	12
Others	3279	1336	220	209	196	185	174	164	155	146	108	90
Total			670	612	562	516	474	437	402	372	250	199

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REFERENCES

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